March 2002

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Caucasus Region

The Caucasus Region, comprising the newly independent states of Armenia, Azerbaijan, and Georgia, is important to world energy markets as a transit area for oil and natural gas exports from the Caspian Sea to Europe. Although the region has been beset by conflict, regional leaders hope that the development of several oil and natural gas export pipelines will bring peace and prosperity to the Caucasus.

Note: Information contained in this report is the best available as of March 2002 and is subject to change.

GENERAL BACKGROUND

The Caucasus region has been fought over by outside powers for centuries, but in 1991, Armenia, Azerbaijan, and Georgia received their independence from the Soviet Union. However, the Soviets bequeathed a number of problems on the three countries, including artificially drawn national borders and centrally-planned economies that were heavily dependent on Russia. Even before Azerbaijan and Armenia received independence, fighting broke out in 1988 between the then-Soviet republics over the disputed area of Nagorno-Karabakh, and separatist conflicts sparked in Georgia soon after independence. Although most of the regional conflicts that flared in different parts of the Caucasus throughout the 1990's are now dormant, none have been officially resolved.

Each of the Caucasus countries has experienced a severe economic downturn since the Soviet era. Conflicts in the region have discouraged foreign investment, and the lack of economic and political reform, along with the continuing hostilities between Azerbaijan and Armenia, have limited the region's economic growth. Although each of the countries is, to different degrees, trying to wean itself off dependency on Russia, Armenia, Azerbaijan, and Georgia remain economically linked to Russia.

Despite their geographical proximity, Armenia, Azerbaijan, and Georgia all have different strategies to diversify their energy suppliers and reduce their dependence on Russia. While Azerbaijan looks to the development of its domestic oil and natural gas reserves for an economic boom, Georgia is merely trying to keep electricity on for its citizens. Thus, Georgia is counting on transit oil and natural gas transit from the Caspian Sea region to boost its growth outlook: tariffs from transit oil pipelines will feed the government's budget, while fuel received from natural gas pipelines will fire Georgian electric-generating plants. Armenia, which is fighting a blockade by Azerbaijan and Turkey, does not figure to benefit substantially from the east-

west pipelines that are in development, is cultivating closer ties with Iran in order to diversify its energy sources.

With a number of regional energy projects in development, Georgian President Eduard Shevardnadze expressed his hope that additional cooperation in the Caucasus will lead to greater trust and increased prosperity for the three countries. Until economic and political reforms take root, however, and a lasting peace is implemented, economic growth in the Caucasus likely will continue to lag behind other regions undergoing the transition from communism to democracy.

REGIONAL ENERGY ISSUES

The Caucasus region's energy importance stems from its location as a land bridge between the Caspian Sea and the Black Sea. Although the region itself does not have significant fossil fuel resources, except in the east of Azerbaijan, the Caucasus provides a link between the bountiful oil and natural gas reserves of the Caspian Sea region and the energy-hungry economies of Turkey and the European Union (EU).

The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk Road) was launched at a European Union (EU) conference in 1993, bringing together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an east-west axis. As oil and natural gas production in Central Asia and the Caspian region increase, the Caucasus has the potential to become a major transit center for oil and natural gas supplies heading west to world markets.

Oil Transit

With the collapse of the Soviet Union and the increase in oil production from the Caspian Sea region, the Caucasus region has gained in importance from an energy perspective. Previously, the only way for Caspian Sea region oil exports to reach European consumers was via the Russian pipeline system. The United States has supported the principle of multiple export options for Caspian exporters, and a number of Caspian region oil export pipelines are planned or already have been built. Many of these pipelines are routed via the Caucasus, and the region has become the central component of a European Union strategy to direct Caspian oil to European consumers.

Baku-Ceyhan Pipeline

In November 1999, Azerbaijan, Georgia, and Turkey signed agreements affirming the Baku-Ceyhan route as the Main Export Pipeline (MEP) for Azeri oil exports. The planned 1-million-bbl/d capacity pipeline, which has received backing from the United States, will run 281 miles through Azerbaijan, 135 miles through Georgia, and 622 miles through Turkey, and is expected to cost between $2.8 billion and $2.9 billion.

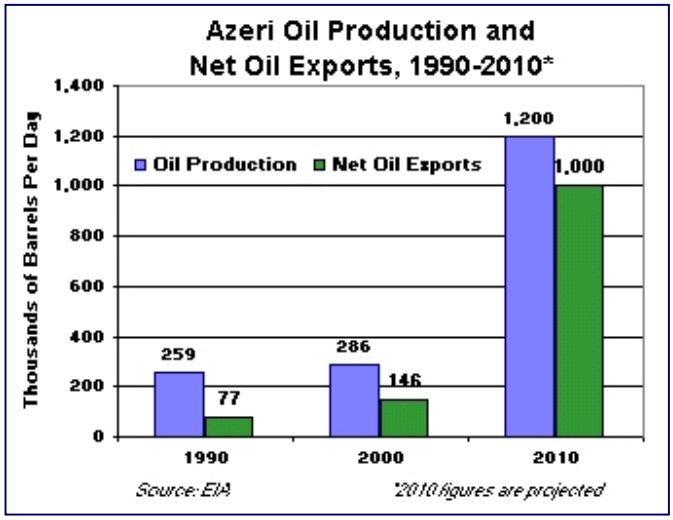
Despite initial opposition to the pipeline, which several oil companies criticized as too costly and uneconomical with the planned volumes from Azerbaijan, construction on the pipeline appears set to begin in the summer of 2002, with a planned launch date at the end of 2004. Detailed engineering work for the pipeline began in June 2001 and is slated to finish in June 2002, identifying a 50-yard-wide corridor through each of the three countries to lay the pipeline. Tenders have been announced to lay the pipeline in Georgia and Azerbaijan (Botas will lay the Turkish section of the pipeline).

Baku-Supsa Pipeline

On March 8, 1996, Georgian President Eduard Shevardnadze and Azerbaijani President Heydar Aliyev signed a 30-year agreement to pump a portion of the Azerbaijan International Operating Company (AIOC)'s "early oil" via Georgia to its Black Sea port of Supsa. The Georgian International Oil Company, a subsidiary

of the AIOC, made substantial upgrades to the existing 515-mile pipeline along this route and built the $565-million Supsa terminal on the Black Sea.

The so-called "western route", which became operational in April 1999, had an original design capacity of 100,000 bbl/d, but recent upgrades have raised capacity closer to 145,000 bbl/d. Officials from BP, the British-based operator of AIOC, said that the consortium exported approximately 130,000 bbl/d in 2001, with virtually all of its oil available for export being shipped to Supsa. The Baku-Supsa route, however, was designed to carry only the early oil from the AIOC's development of the Azeri-Chirag-Gunashli fields, and although there has been discussion of increasing the pipeline's capacity to 300,000 bbl/d or even 600,000 bbl/d, AIOC is planning to export its future production via the Baku-Ceyhan Main Export Pipeline, once it becomes operational.



Baku-Novorossiisk Pipeline
The 100,000-bbl/d-capacity Baku-Novorossiisk pipeline, also known as the "northern route", opened in 1997. The pipeline runs 868 miles from Baku via Chechnya to the Russian Black Sea port of Novorossiisk. Initial exports through the pipeline were limited to approximately 40,000 bbl/d, however, owing to pumping limitations, disputes over transit tariffs, and the conflict in Chechnya. Up to 70,000 bbl/d of oil was forced to bypass Chechnya by rail from Dagestan to Stavropol.

The ongoing conflict and instability in Chechnya prompted Russian pipeline operator Transneft to construct a 120,000-bbl/d Chechnya pipeline bypass (160,000 bbl/d including rail links). This bypass, which was completed in 2000, includes an 11-mile spur to Russia's Caspian Sea port of Makhachkala. The pipeline and spur could eventually transport up to 360,000 bbl/d of oil, enabling additional exports from Azerbaijan, Kazakhstan, and Turkmenistan to flow through the pipeline from Baku and Makhachkala.

In 2000, Azerbaijan's SOCAR committed itself to throughput of 46,000 bbl/d, but in the end only transported around 10,000 bbl/d, prompting Transneft to accuse Azerbaijan of not fulfilling its commitment to export oil along the bypass. The AIOC, which also was expected to export via Baku-Novorossiisk, has been reluctant to send its oil along this route because it is longer and more expensive than the Baku-Supsa route, and also because the northern route mixes AIOC crude with other crude oils while in transit to Novorossiisk, reducing its value.

SOCAR exported approximately 50,000 bbl/d via the Baku-Novorossiisk route in 2001, and plans to maintain that rate in 2002. Russia says the the capacity on Baku-Novorossiisk can be increased to 300,000 bbl/d, but SOCAR will not have sufficient volumes to fill the pipeline, even at its present capacity, in the next few years. Future Azeri oil production, mainly from the AIOC, is slated to be exported via the Baku-Ceyhan pipeline, although Transneft claims that exporting via the Baku-Novorossiisk pipeline would be cheaper.

Other Oil Transit
Prior to the opening of the CPC pipeline in the fall of 2001, ChevronTexaco had been delivering oil from the Tengiz field in Kazakhstan via the Caucasus. ChevronTexaco sent its oil across the Caspian by barge to the Dubendi terminal in Azerbaijan, where it was further transported via a pipeline to Ali-Bayramly (Azerbaijan),

and then to Georgia's Black Sea port at Batumi in rail cars. In September 1999, Chevron (as it was then known) and Georgian company Geoengineering signed an agreement on the preparation of a feasibility study for the reconstruction of the Khashuri-Batumi, with an eye towards using the pipeline for transiting Tengiz crude. Together with an upgrade of the Batumi refinery, the project was estimated to cost $100 million.

With the launch of the CPC, however, ChevronTexaco decided in May 2001 to cancel the project to reconstruct the Khashuri-Batumi pipeline, saying that the pipeline was economically unfeasible, especially since most of the Tengizchevroil exports are now routed via the CPC. Nevertheless, Tengiz crude has been replaced at the Batumi port by high-quality Kumkol crude, supplied by Euro Asian Trading, and the lower-quality Buzachi blend, produced by Kazakhstan's Mangistaumunaigaz, both of which reach Batumi via a combination of barge, pipeline, and rail across the Caspian and the Caucasus. Turkmenistan also exports occasional cargoes of Cheleken and Okarem crude, which are mostly blended with the Kazakh oil either at the Batumi terminal or on barges, forming a "synthetic Urals" blend.

Rail cars loaded with oil from Ali Bayramly are beginning to overwhelm the Georgian Black Sea ports. Although throughput at the Batumi terminal was 120,000 bbl/d in February 2002, with 400 tank cars per day offloaded, Azerbaijan was sending more than 500 tank cars per day, leaving over 100 tank cars per day unloaded. The backlog in offloading tank cars at the Georgian ports has led to a shortage of tank cars in Azerbaijan. In May 2001, the EBRD agreed to finance the construction of a $20-million oil terminal at the Black Sea port of Poti. The Poti terminal will be able to handle up to 50,000 bbl/d, proving an alternative to the main port at Batumi.

In addition, Georgia and Turkey are working on plans to utilize a 172-mile railway line between Tbilisi and Kars, Turkey, to transport up to 200,000 bbl/d of crude oil from the planned Baku-Ceyhan pipeline to Turkish refineries. The railway plan, which could cost $400 million, will require refurbishing an existing line from Tbilisi to Akhalkalaki for $200 million, as well as extending the rail line 77miles to Kars.

Natural Gas Transit

The Caucasus region also is set to become a major transport corridor for natural gas. Most of this will come from increased Caspian Sea region natural gas production, especially from Azerbaijan. As Azerbaijan begins to exploit the Shah Deniz natural gas field, which has estimated reserves of 35.3 trillion cubic feet (Tcf), its natural gas production will rise dramatically, and the country's March 2001 agreement with Turkey will allow Azerbaijan to boost its natural gas exports by piping Shah Deniz supplies via Georgia to Turkey. In addition, Armenia and Iran are developing a natural gas pipeline to connect the two countries, with the pipeline possibly continuing further northwards to connect to Georgia and then to the Russian pipeline system.

Baku-Erzurum Pipeline

On March 12, 2001, Azerbaijan and Turkey reached a natural gas export deal whereby Azerbaijan will supply Turkey with 3.1 trillion cubic feet (Tcf) of natural gas from 2004 through 2018. To deliver the natural gas to Turkey, BP, the operator of the Shah Deniz field, announced on March 14, 2001, plans to build a 1.06-Tcf-per-year-capacity pipeline from Baku to Erzurum, Turkey, via Georgia. Originally, Azerbaijan had hoped to use part of the existing Gazi-Magomed-Gazakh pipeline to transport the natural gas across Azerbaijan, but technical inspection of the pipeline deemed that costly repairs would first be necessary, and the huge volume of natural gas that Azerbaijan agreed to export--exceeding the capacity of the Gazi pipeline--necessitated that a new pipeline be built.

After lengthy negotiations that threatened to negate Azerbaijan's export deal with Turkey, in September 2001,

Georgia and Azerbaijan cleared a major hurdle for the pipeline by signing a transit agreement. The agreement calls for Georgia to receive 5% of the natural gas in the pipeline, as well as preferential rights to purchase additional natural gas from the pipeline for 20 years, in exchange for transit rights. The Azeri parliament ratified the transit agreement in October 2001, followed by the Georgian parliament in December 2001. In January 2002, Georgian announced it will build two, 88.3-Bcf-capacity underground natural gas storage facilities in the east and southwest of the country as part of the pipeline project.

The Baku-Erzurum pipeline will stretch some 630 miles, including 290 miles in Azerbaijan and approximately 170 miles in both Georgia and Turkey. Detailed engineering for the pipeline, which will mirror the Baku-Ceyhan oil pipeline to Erzurum, is in progress, with tender proposals being prepared for construction of the Azeri and Georgian sections of the pipeline (Turkey's Botas will construct the Turkish section of the line). Currently, the pipeline project is estimated to cost $1 billion. Credits to be drawn from international financial institutions, including the World Bank, European Bank for Reconstruction and Development (EBRD), International Finance Corporation (IFC), and investors from the United States and Japan are expected to cover 70% of the pipeline's construction costs, while shareholders in the development of the Shah Deniz field development will contribute the remaining 30%.

Construction of the Baku-Erzurum pipeline is scheduled to begin in late 2002 and to be operational by the end of 2004. Initial capacity on the pipeline is slated to be 777 billion cubic feet (Bcf) per year, with capacity eventually rising to 1.06 Tcf per year. With natural gas production in the first stage of exploitation of the Shah Deniz field expected to be 282 Bcf per year, the Baku-Erzurum pipeline will have excess capacity to pipe additional Caspian Sea region natural gas exports, possibly from Turkmenistan if the Caspian littoral states agree on a legal regime for the Sea, allowing the proposed Trans-Caspian Gas Pipeline to be built. In addition, Turkey is in consultations with Greece to extend the Baku-Erzurum pipeline into the territory of the European Union.

Iran-Armenia Pipeline

Armenia and Iran are pushing ahead with a long-standing project to build an 84-mile natural gas pipeline linking the two countries. The pipeline project, dating back to intergovernmental agreements signed in 1992 and 1995, would allow Armenia to diversify and stabilize its natural gas supply sources, as well as expedite the closing of Armenia's Metsamor Nuclear Power Plant, which the European Union considers dangerous.

Implementation of the project has been delayed for years due to disagreements between the two sides over natural gas prices and the location of the pipeline. The original proposal was for the pipeline to be laid from northwestern Iran to the existing Armenian pipeline that terminates in Kadzharan, requiring the pipeline to transit the Azeri exclave of Nakhichevan. However, the still unresolved hostilities between Azerbaijan and Armenia over Nagorno-Karabakh made this plan impossible. In addition, Armenia balked at the high price of natural gas (from $84 to $90 per 1,000 cubic meters) that the Iranian side set for the pipeline.

Although the two sides have not been able to agree on a price for Iranian natural gas, in December 2001, Armenia and Iran signed a transit agreement to allow Armenia to import Turkmen natural gas via Iran. Turkmenistan is linked to the Iranian natural gas pipeline network through the Korpezehe-Kurt Kui pipeline, which opened in December 1997. The Iran-Armenia pipeline is now slated to cover 84 miles, running from Tabriz to Khadzaran and bypassing Nakhichevan. An initial feasibility study for the pipeline, with initial capacity of 35.3 Bcf and possibly up to 106 Bcf per year, has been completed.

The estimated cost of the Iran-Armenia pipeline is $120 million. The European Union has declared its

readiness to assist in financing the pipeline's construction, but Gazprom and Itera, both of which previously expressed an interest in participating, announced that they would participate in the construction only through their partial ownership of Armrosgazprom, Armenia's natural gas distributor. France's Gaz de France previously announced its intention to invest in the pipeline, but has not committed to the project. Any significant investment in an Iranian oil project may be subject to the Iran and Libya Sanctions Act, which the U.S. Congress renewed in August 2001.

Once financing for the pipeline is secured, construction can commence. During the first stage of construction, which Armenia hopes to begin in 2002, Armenia will lay a 24-mile pipeline section from Kadzharan to the southern border at Megri for approximately $26 million. Ukraine, which currently imports significant amount of Turkmen natural gas via Russia, has suggested that the Iran-Armenia pipeline be linked to its proposed route from Turkmenistan through Iran and Armenia. In addition, once the Iran-Armenia pipeline is completed, it will link the Iranian and Russian natural gas transportation systems, allowing for possible Iranian natural gas exports to Europe through the Russian pipeline system.

Other Natural Gas Transit in the Caucasus

In November 2000, Georgia approved a project for a 37-mile pipeline to carry Russian natural gas to Turkey via the Georgian Black Sea coast. After a September 2001 meeting, Georgian officials announced that representatives from Conoco and Turkey's Acsoy Group were ready to invest in the pipeline, which would transport 35.3 Bcf per year of natural gas from Kobuleti, Georgia, to Hopa, Turkey.

Georgia also has held discussions with Gazprom on refurbishing the existing North Caucasus-Transcaucasian natural gas pipeline and extending it into a trans-Georgian pipeline to bring Russian natural gas to Armenia and Turkey. However, this idea has lost some support as Russia focuses on delivering its gas to Turkey via the "Blue Stream" natural gas pipeline under the Black Sea.

The Caucasus region may also serve as a transit region for liquefied natural gas (LNG). Conoco, together with the Acsoy Group, began a project to supply liquefied gas from Russia and the Caspian region to Turkey in 1999. However, the volume of natural gas supplies was small, and Conoco withdrew from the project. In September 2001, Batumi Oil Terminal Ltd., which owns the Batumi terminal, said that it would continue developing the project, where LNG will be barged from Kazakhstan and Turkmenistan across the Caspian to Baku, then transported using rail and sections of the natural gas pipelines in Georgia to Batumi. From there, the LNG will be sent to Turkey and other Mediterranean customers.

ARMENIA

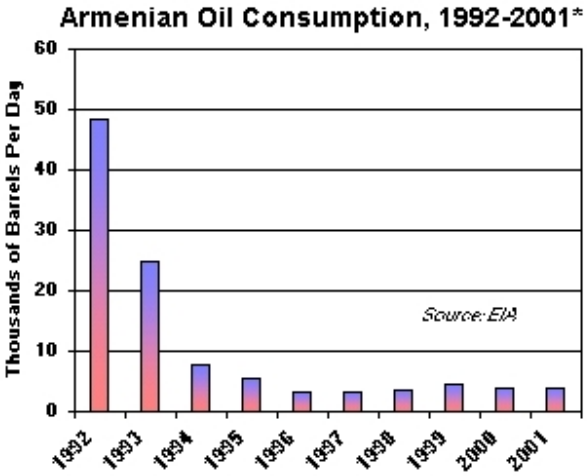
Following a severe economic decline in the early 1990's, Armenia is continuing its slow recovery from the collapse of the Soviet Union and the effects of Armenia's six-year war with Azerbaijan over Nagorno-Karabakh. In 1994, Armenia launched an ambitious International Monetary Fund-sponsored economic program that has resulted in positive growth rates for the past eight years, despite the Azerbaijani-led economic blockade of Armenia.

Armenia's small- and medium-sized enterprises, most of which have already been privatized, have spurred continuing economic growth. The country's economy registered strong growth in 2001, with real gross domestic product (GDP) increasing 7.2%, up from 6% growth in 2000. Armenia's real GDP is forecast to grow by 5.4% in 2002. Inflation rose only slightly in 2001, to 3%, from 0.4% in 2000, and Armenia's unemployment rate dropped from 11.7% in 2000 to 10.5% in 2001. At its current growth rate, by 2005, Armenia's absolute GDP will reach the same level as in 1991, the year that the Soviet Union and its central

economic planning system collapsed..

Oil

Armenia has no oil production, known reserves, or refineries, making the country completely dependent on imports of refined petroleum products. In addition, because there are no oil pipelines into Armenia, all of the country's petroleum products must be imported by rail or by truck. Since the end of subsidized oil supplies after the collapse of the Soviet Union, Armenia's oil consumption has dwindled from 48,400 barrels per day (bbl/d) in 1992 to just 4,000 bbl/d in 2001, most of which comes from the Batumi refinery in western Georgia.



*Note: Armenia produces no oil; all oil is imported.

Although the planned "Main Export Pipeline" (MEP) for Caspian region oil is not slated to transit Armenian territory, Armenian officials occasionally have spoken of potential cost savings if the MEP were built through northern Armenia, since it would shorten the export route considerably. However, the lack of a peace agreement between Armenia and Azerbaijan over Nagorno-Karabakh makes this idea extremely unlikely. Azerbaijani officials have dismissed the idea altogether, noting that the route through Georgia already has been decided.

Natural Gas

With no proven natural gas reserves, Armenia is reliant on imports to meet its domestic natural gas demand. In 2000, Armenia consumed 49.8 Bcf of natural gas. Since the Nagorno-Karabakh conflict erupted, Azerbaijan has ceased natural gas shipments into Armenia from the Soviet-era natural gas pipeline linking the two countries, forcing Armenia to import all of its natural gas via the Georgian and Russian natural gas pipeline networks to the north. The private natural gas trading company Itera has been Armenia's main natural gas supplier since 1996. The proposed Iran-Armenia natural gas pipeline will allow Armenia to diversify its natural gas suppliers, with Turkmen natural gas to be piped via the Iranian pipeline network to Armenia.

Natural gas in Armenia is distributed by Armrosgazprom, a closed joint-stock company owned by the Armenian government (45%), Russia's Gazprom (45%), and Itera (10%). Armrosgazprom planned to re-invest $6 million from its own funds in 2001 in an effort to rehabilitate Armenia's natural gas sector. In February 2001, Armenia and Russia reached an agreement on Armenia's $7-million debt for natural gas shipments dating back to 1999, which Itera supplied on Gazprom's behalf. Since Gazprom and Itera owed Armenia their contribution to the incorporation capital of Armrosgazprom, in July 2001, Itera agreed to write off Armenia's debt in exchange for the Armenian government transferring its natural gas pipelines to the joint enterprise towards Russia's share.

Armenia has continued to rack up natural gas debts to Itera, prompting the company to reduce supplies to Armenia in October 2001 to force payment. In late January 2002, Itera again threatened to reduce natural gas shipments to Armenia by two-thirds unless Armenia stayed current in its payment for supplies. In mid-February 2002, Itera announced that it had decided not to alter the level of natural gas supply to Armenia because the country honored a January 11, 2002, agreement to pay its debt for the natural gas acquired in 2001 and January 2002.

Coal

Armenia has no coal reserves or coal production. Armenia's coal consumption, most of which is used for home heating, totaled 3,307 short tons in 2000.

Electricity

Armenia's power sector has a total installed generating capacity of 2.7 gigawatts (GW). The country has two large thermal power plants--at Yerevan (550 megawatts, MW) and Hrazdan (1,110 MW)--as well as a smaller plant at Vanadzor (96 MW). Armenia also has significant hydroelectric power-generating ability and one nuclear power plant. In 2000, Armenia generated 5.7 billion kilowatt-hours (Bkwh) of electricity and consumed just 4.9 Bkwh, but since power is not provided to all regions of the country on a regular basis, the country's potential demand for electricity outpaces supply. In addition, the thermal plants have exceeded their projected operating lifespan, are in need of renovation, and are often low on fuel, since Armenia must import all of its natural gas.

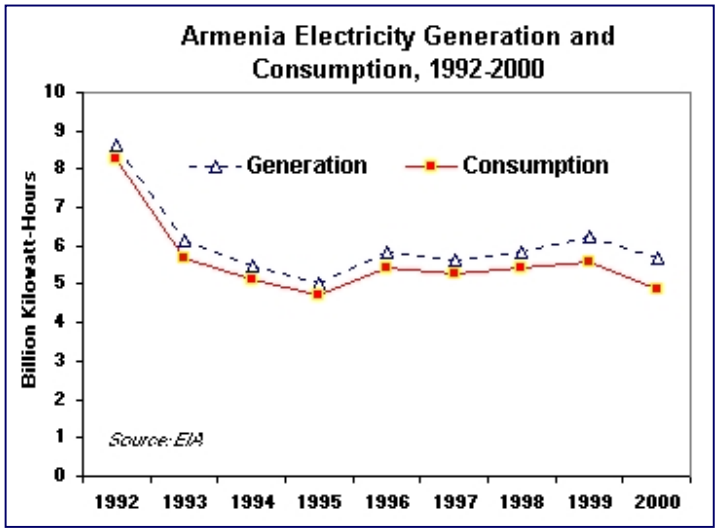
Iran and Armenia already have linked their electricity grids, allowing for power sales in both directions driven by seasonal differences in demand between the two countries. In summer, Armenia exports its power to Iran and gets it back in winter. Armenia also supplies some of its surplus seasonal electricity to Georgia. Closer ties with Iran could give Armenia an additional source of electricity as Iran, Turkmenistan, and Armenia explore whether their power grids can be linked. Armenia could receive electricity from Turkmenistan via Iran's energy system at less than the price of power produced by its own power stations.

Privatization

In 1998, Armenia's parliament passed a law allowing for the sale of the country's electricity transmission and distribution networks, while keeping power generation under government control. In an effort to support Armenia's privatization efforts, on December 5, 2000, the European Bank for Reconstruction and Development (EBRD) signed an agreement with the Armenian government to take 20% equity stakes in each of the country's four electricity distribution companies: Yerevan, Northern, Southern, and Central. The agreement, which lasts for five years, includes a clause giving the Armenian government the right to buy back the EBRD shares should the agreement be abrogated.

U.S.-based AES Silk Road, ABB Energy Ventures of Sweden, and Spanish Union Fenosa Acex had been among the companies initially interested in the networks when the privatization tender was announced. However, the privatization process stalled in March 2001, when Armenian authorities announced they had not received any bids for the 75% stake in the first two distribution networks. In April 2001, the second stage of the tender also failed to attract any bidders. Armenia is now looking to implement additional needed reforms, including possibly unifying the distribution grids into one, before proceeding with another privatization tender for the distribution networks. In September 2001, Armenian Energy Minister Karen Galustian said that Russia's Unified Energy Systems, Gazprom, and Itera likely will participate in the eventual privatization.

Metsamor Nuclear Power Plant



Armenia has one nuclear power plant, the controversial Metsamor Nuclear Power Plant (NPP). The power plant, with two VVER-design reactors and a combined capacity of 815 MW, was shut down in March 1989 by the Soviet Union because of safety fears following the devastating earthquake that struck Armenia in December 1988.

However, faced with a deepening energy crisis due to the country's lack of fossil fuels and the economic blockade imposed by Azerbaijan and Turkey, on November 5, 1995, Armenia decided to resume operation at the 440-MW second unit. The plant, which was built in 1980 with a design life of 30 years, now supplies between 40% and 45% of the country's electricity.

Since the Metsamor NPP was inactive for six years, Armenian and Russian nuclear officials believe that the lone reactor functioning at the plant could operate through 2016. The European Union, however, is pressuring Armenia to shut the plant earlier, since the EU considers Metsamor to be a safety risk due to flaws in the plant's Soviet-designed reactors and the region's seismic activity. In July 2001, Unit 2 at Metsamor was halted for planned maintenance and was supposed to be back in operation by the end of August, but debts delayed the reactor's launch: Armenia owed Russia $17 million for nuclear fuel already supplied, with the cost of new fuel set at $14 million. Armenia finally re-started the reactor in November 2001. Experts have estimated that required safety upgrades at the plant will cost about $1 billion over the next 15 years.

Rather than increasing spending to maintain the Metsamor NPP, the Armenian government has pledged to decommission the plant by 2004, provided the country has sufficient alternative energy sources by that time. The EU is pledging Armenia 100 million euros ($91 million) to build alternative power-generating facilities to replace Metsamor. However, Armenian Energy Minister Karen Galustian said that the country will need up to $1 billion from foreign investors and donor countries to safeguard Armenia's energy security after closing Metsamor.

Hydroelectric Power

Hydroelectricity accounted for almost 25% of Armenia's electric power generation in 2000. Armenia has several hydroelectric plants on the Hrazdan River, including the Sevan-Hrazdan hydroelectric plant, and has plans to develop several additional hydroelectric projects. Armenia is undertaking a program to construct 38 small and three large hydroelectric power plants, with an overall capacity of 296 MW. The cost of this program will be $300 million, part of which will be financed by the World Bank and the EBRD.

Of the three large hydropower plants, two--Lori Berd and Shnokh--will be built in the Armenian northeast, one with a capacity of 60 MW and an annual output of 192 million kilowatt-hours, and the other with a capacity of 75 MW and an annual output of 300 million kilowatt-hours. The third proposed hydropower plant, at Megri on the Araks river on the Armenian-Iranian border, is slated to have a capacity of 78.9 MW and to generate 469 million kilowatt-hours of electricity a year. Armenia and Iran have set up a joint company to construct the Megri hydroelectric power station, which will cost from $60 million to $80 million and take over five years to build. However, Azerbaijan has objected to the proposed plant, arguing that its Nakhichevan exclave will have its water supplies severely decreased if the Megri hydroelectric power station is constructed.

AZERBAIJAN

For detailed information on Azerbaijan's energy sector, visit the Azerbaijan Country Analysis Brief.

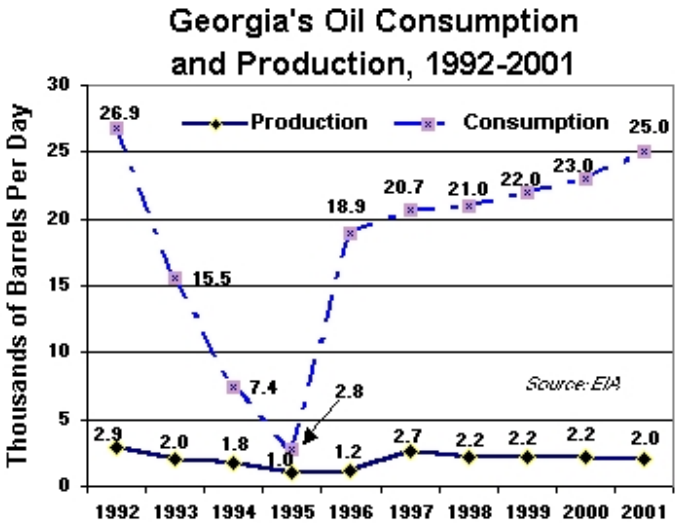
GEORGIA

More than ten years since Georgia's independence from the Soviet Union, the country continues to suffer from political turmoil, civil strife, and a weak economy. Although President Eduard Shevardnadze restored order following the overthrow of Georgia's first democratically elected president, separatist struggles in Abkhazia (northwest Georgia) and South Ossetia (north central Georgia), along with entrenched corruption, discouraged foreign investment throughout the 1990's. As a result, Georgia's economy, which was already reeling from the loss of Soviet subsidies after independence, suffered through bouts of hyperinflation and severe economic contraction--by 1995, Georgia's GDP dropped to 20% of 1990 levels.

Since the mid-1990s, however, Georgia has progressed slowly, bringing inflation under control, introducing a stable currency, and experiencing moderate economic growth. In 2001, Georgia's real GDP grew by 4%, and the country's economy is projected to grow by 3.2% in 2002. Georgia's agricultural sector rebounded in 2001 after a drought in the summer of 2000 had disastrous effects, both on food supplies and on the country's hydropower potential, Georgia's only sizable internal energy resource. Power generation continues to be a problem in Georgia, and the unresolved conflicts in Abkhazia and South Ossetia have strained Georgian-Russian relations, as well as hindered economic growth in the country.

Oil

Georgia's has limited oil reserves, with approximately 35 million barrels, and the country's small oil industry does not produce enough to meet domestic needs. In 2001, Georgia produced approximately 2,000 bbl/d of oil, far short of the 25,000 bbl/d of oil that that the country consumed. CanArgo-Georgia, also known as the Georgian-British Oil Company (GBOC), is Georgia's leading producer, with an average of 1,200 bbl/d of oil produced from the Ninotsminda field in 2001. Saknavtobi (Georgian Oil), the state oil company, produced just 120 bbl/d of oil in 2001. Georgia is expected to produce around 2,000 bbl/d in 2002.



As Georgia continues its recovery from civil strife in the mid-1990s, oil consumption is on the rise, but so is investment in the country's oil sector. According to the Georgian National Oil and Gas Regulating Agency, around $125 million has been invested in Georgia's oil production sector in the past five years. Georgian authorities have estimated that, between 2001 and 2005, an additional $453 million will be invested in oil and natural gas exploration and production in Georgia by nine joint ventures. The country is pinning its hopes on a dramatic increase in domestic oil production in order to meet rising demand in the next decade.

Active exploration is underway in Georgia, both along the Black Sea coast and onshore. The joint ventures are conducting operations in a number of blocks, including Ninotsminda, Manavi, Rustavi Kartli, Samgori, Patardzeuli, Mtiani Kakheti, Mirzaani, Taribana, Patara Shiraki, Nazvrebi, Supsa, Chaladidi, and Shromisubani. Saknavtobi and Anadarko (U.S.) have worked out a package of production-sharing agreements

on the Black Sea shelf, where exploration engineers have discovered roughly 580 million tons of oil (4.25 billion barrels), including about 200 million tons (1.47 billion barrels) offshore.

Georgia has negotiated production-sharing agreements and joint ventures with a number of companies, including an agreement with the German company GWDF International to develop the Chaladidi, Supsa, and Shromisubani fields in western Georgia, and with Frontera Eastern Georgia, a Georgian-American joint venture, to develop the Taribana field in Kakhetia. According to a program developed by Saknavtobi based on investment projects currently being carried out by oil joint ventures in Georgia, the country could produce up to 4 million tons of oil between 2001 and 2005 (an average of 16,000 bbl/d).

Downstream/Refining

Georgia has two refineries, a 106,000-bbl/d refinery at Batumi, and a smaller, 4,000-bbl/d refinery at Sartichala, the Georgian-American Oil Refinery (GAOR). The Batumi refinery, however, currently is undergoing a $250-million modernization and expansion by Japan's Marubeni Corporation and the JGC Corporation, forcing Georgia to import over 90% of the petroleum products it consumes.

After sitting idle for much of 2001, the GAOR refinery, which was built in 1998 and is owned by Canadian CanArgo (51%), Saknavtobi (28%) and GBOC (21%), ramped up operation in July 2001, processing about 8,000 tons of crude oil (an average of 1,928 bbl/d for the month) into gasoline, diesel and fuel oil. However, difficulties in selling the gasoline, as well as the plant's less than 50% utilization rate, forced management to begin to shut down the facility again in August 2001. In September 2001, CanArgo announced it was closing the GAOR refinery, saying that prices for crude oil and the saturation of the domestic market with cheap oil products from Azerbaijan and Russia had made operation of the small refinery unprofitable.

Rather than continuing operations at the GAOR refinery, CanArgo announced plans to build a larger refinery at the same site. The Canadian company announced it would build a $200-million refinery that would be able to process up to 1.5 million tons of crude oil per year (30,100 bbl/d). Additionally, Switzerland's National Petroleum Limited (NPL), which has been developing Georgia's biggest oil field with Sakvnavtobi since 1996, revealed plans in July 2001 to construct a 40,000-bbl/d refinery in Georgia in the next few years. Georgia also has awarded Frontera the right to construct a new refinery near Tbilisi as part of its production-sharing agreement.

Natural Gas

Georgia has approximately 300 Bcf in natural gas reserves, and during Soviet times the country did not produce any natural gas. Since Georgia became independent in 1991 and stopped receiving subsidized fuel, the country's natural gas consumption has plummeted, from 177 Bcf in 1992 to just 42.7 Bcf in 2000. Although the country's natural gas sector increased output from zero in 1997 to 2.1 Bcf in 2000, Georgia remains heavily dependent on foreign suppliers to meet its domestic demand.

In addition, Georgia's inability to pay its suppliers has limited the country's consumption, as both Russia and Turkmenistan at times have cut off natural gas supplies to Georgia due to payment arrears. Turkmenistan has left the Georgian natural gas market, claiming that Georgia still owes it for past supplies, leaving Russia as the country's sole supplier. Itera, the Gazprom-affiliated natural gas trader, has been supplying Georgia for the past year, but the company repeatedly has reduced supplies to Tbilisi in order to force Georgia to pay its bills. As of December 2001, Georgia owed Itera about $90 million for previous natural gas supplies, prompting Itera to require prepayment for natural gas shipments to Georgia after January 1, 2002.

Georgian leaders hope to decrease this reliance on natural gas imports in coming years by courting foreign investors to develop the country's natural gas deposits and by reforming the country's natural gas distribution system. However, to date, there has been little interest among international energy companies in Georgia's natural gas production potential, and attempts to private Tbilgaz, the municipal natural gas distribution company serving Georgia's capital, have failed repeatedly. In June 2001, Georgia once again offered an international tender for an 85% stake in the Tbilisi distribution network. With the network only 25% operational, no bids were received.

Energy companies have had more interest in Georgia's natural gas transmission sector, mainly due to the country's burgeoning role as a transit center for natural gas exports from Azerbaijan. The Georgian International Gas Corp., which runs the country's transmission system, has been working on a program to modernize Georgia's internal natural gas pipelines, which stretch over 6,000 miles, in order to pump Azeri natural gas via Georgia for the planned Baku-Erzurum pipeline. In October 2001, the Georgian International Gas Corp. and Russia's Gazprom joined forces to create Gruzrosgazprom, a joint venture that will develop and operate the natural gas transport system in Georgia. The Georgian International Gas Corp. owns 51% of the joint venture.

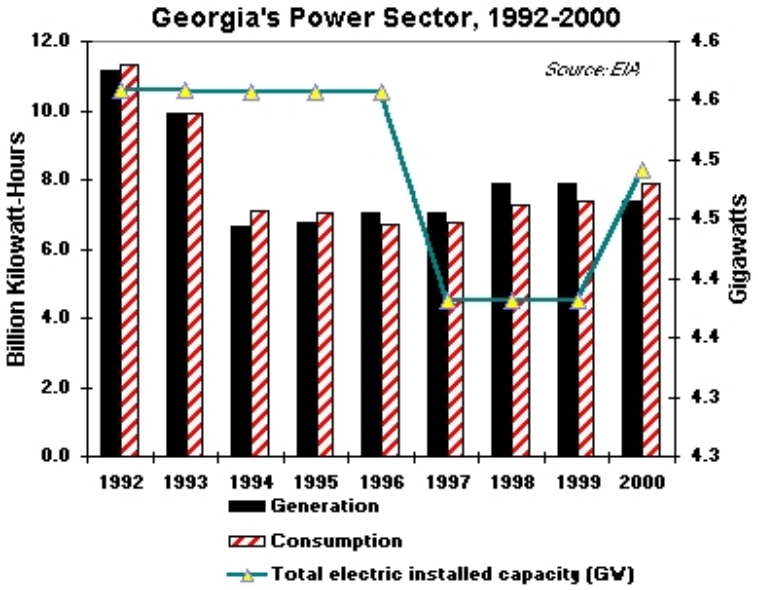
With Azerbaijan's October 2001 decision to rehabilitate a 23-mile pipeline to the Georgian border, Georgia will be able to import between 7 Bcf and 10.5 Bcf of natural gas from Azerbaijan in 2002. Additionally, the natural gas transit agreement signed by the two countries in September 2001 stipulates that Georgia will receive 5% of the natural gas shipped via the Baku-Erzurum pipeline when it comes online in 2004. Under the transit agreement, Georgia also will have the right to purchase 500 million cubic meters (17.7 Bcf) of natural gas per year for 20 years at a cost of $55 per 1,000 cubic meters (35,300 cubic feet).

Coal

Georgia's coal output, already low by world standards in 1991 when the country became independent, has decreased in the past decade. Between 1992 and 1997, the country's coal production declined from 220,462 short tons to 5,952 short tons--a drastic 97% reduction--although production has rebounded slightly, to 22,046 short tons in 2000. Similarly, Georgia's coal consumption plummeted 95% from 1992 to 1997, from 480,607 short tons to just 22,000 short tons, before climbing back to 37,479 short tons in 2000.

Electricity

Georgia's energy system includes about 60,000 miles of transmission lines, 53 hydroelectric power stations, and three thermal power plants, for an overall generating capacity of 4.5 GW. However, fuel shortages and aging power plants means that the sector is only able to operate at 40% of capacity. Georgia consumed more electricity than it generated in 2000: 7.9 Bkwh consumed compared to 7.4 Bkwh generated. In addition, because of inefficient and deteriorating power lines, power outages are a daily occurrence in much of the country, and parts of Georgia do not receive any electricity at all.



Georgia's total electricity demands have been estimated at nearly twice the amount that is actually generated, and the Georgian Energy Ministry estimates

that 40% of all power that is generated is wasted due to equipment and maintenance problems in the transmission sector. To meet some of its power needs, Georgia imports electricity from Armenia, Azerbaijan, and Russia. Georgia has run up large electricity debts to each of the countries. In addition, because Georgia's natural gas supplies frequently are cut off due to the country's payment arrears, Georgia's own natural gas-fired power plants are often short of fuel. As a result, electricity supplies, even to Tbilisi, are erratic, leaving customers in the dark for 20 hours (or more) per day. Consumers, who use kerosene for heating, have responded to rate increases and inadequate power supplies by refusing to pay their electricity bills.

Privatization

The significant problems in Georgia's power sector have hampered the country's economic growth, making energy sector reform a government priority in 2002. In a January 2002 meeting with IMF representatives, Georgian Minister of State Avtandil Jorbenadze said that problems in the energy sector had been caused by rampant corruption and that the process of dealing with them should start with the establishment of a proper wholesale market, the speeding up of privatization of energy sector installations, and the drawing up of clear mechanisms for repayment of the energy sector's internal and external debts.

In an effort to resolve the problems in the power sector, Georgia is trying to reform and privatize Sakenergo, the state energy and power company. With support from the World Bank and the EBRD, most of Georgia's hydro and thermal generation units have been restructured as joint-stock companies, and the Georgian Ministry for the Management of State Property is proceeding with privatization of energy distribution companies. In January 1999, AES (U.S.) purchased a 75% stake in the Telasi electricity distribution company, which serves the Tbilisi area, for $25.5 million. As part of the privatization agreement, AES made a made a further commitment to pay $10 million of Telasi's debt and $80 million in investment to provide consumers with 24-hour electricity.

Power Outages

Although Telasi's debts have stopped growing since AES took it over, AES has not been able to meet its pledge to provide 24-hour electricity because the company continues to receive erratic power supplies from power-generating companies. In addition to the inherent problems of Georgia's power sector, faltering equipment and sabotage by secessionist rebels also have led to power outages across Georgia.

On December 22, 2001, the Unit 10 at the Tbilisi Power Plant exploded, causing severe damage that will take at least a year to restore. AES-Mtkvari, a subsidiary of AES-Telasi that operates the 300-MW generating unit, said that the explosion occurred because the computer control system and the mechanical portion were incompatible. However, in January 2002, Georgia's national energy regulatory commission suspended AES-Mtkvari's license to operate the unit, prompting an AES Vice President to announce that the company will evaluate in the summer of 2002 whether it will remain in Georgia. AES-Mtkvari has owned the two most powerful (300 MW each) power-generating units at the Tbilisi Power Plant since the spring of 2000.

On January 2, 2002, an accident with an electricity transmission line brought electricity supplies to Georgia from Russia and Armenia to a halt. The Kavkasioni high-voltage electricity line, which supplies electricity from Russia to Georgia through regions high in the mountains, broke down for unknown reasons, but the stoppage of supplies from Russia and Armenia had an immediate impact on Georgia's provision of electricity, which was already struggling after the explosion at the Tbilisi Power Plant. After the December incident, Russia increased power supplies to Georgia via the Kavkasioni line. Georgian authorities did not rule out sabotage in the Kavkasioni incident, noting that in November 2001 secessionist rebels destroyed a bridge over the Pankisi Gorge near the Khador Hydroelectric Power Plant.

Hydropower Projects
Georgia is seeking foreign equity participation for both new capacity and rehabilitation hydropower projects. Hydropower accounts for 80% of Georgia's electricity generation, and the country has a substantial amount of untapped hydroelectric potential that could be exploited. Georgia already has made plans to build two new hydroelectric plants on the Rioni River (the 250-MW Namakhvani and the 100-MW Zhoneti), and the country is also hoping to build the proposed 40-MW Minadze station on the Kura river.

In February 2001, Chinese and Georgian officials signed an agreement on the construction of the 24-MW Khador Hydroelectric Power Plant near the Georgian-Russian border in the eastern Kakheti region. In September 2001, the Georgian-Chinese *Energokorporatsia Vostoka* company opened the first phase of the Khador cascade of mini hydroelectric plants. The first mini hydroelectric plant has capacity of 2 MW, and the entire facility will be launched by the end of 2002. Chinese investment in the project totaled $27 million.

In January 2002, Georgian Energy Minister David Mirtskhulava said that China's Sichuan Machinery, which is constructing the Khador Hydroelectric Plant, will invest $10 million in a second hydroelectric station in Georgia. The 9.3-MW plant will be built on the Chelta River in the Kakheti region. According to Mirtskhulava, construction of another hydroelectric plant in Kakheti would end the serious power shortages in the region, which is one of Georgia's biggest agricultural regions.

In addition, in November 2000, Georgia announced a tender for the rehabilitation of the existing Inguri Hydropower Plant, the country's largest. The project, which will cost an estimated $62 million, will boost the station's capacity from its current capacity of 400-450 MW, to 1,300 MW. The EBRD will provide $39 million in the form of a long-term credit, while the EU and Japan will give grants totaling $10 million. Georgia will finance the remaining $13 million.

Table 1. Economic and Demographic Indicators for the Caucasus Region

Country	Gross Domestic Product (Nominal GDP), 2001E (Billions of U.S. $)	Real GDP Growth Rate, 2001 Estimate	Real GDP Growth Rate, 2002 Projection	Per Capita GDP, 2001E	Population 2001E (Millions)
Armenia	$2.1	7.2%	5.4%	$542	3.8
Azerbaijan	$5.2	7.5%	7.0%	$646	8.1
Georgia	$3.1	4.0%	3.2%	$619	5.0
Total/weighted average	$10.4	6.4%	5.5%	$615	16.9

Source: DRI/WEFA

Table 2. Energy Consumption and Carbon Dioxide Emissions in the Caucasus Region, 1999

Country	Total Energy Consumption (Quadrillion Btu)	Petro-leum	Natural Gas	Coal	Nu-clear	Hydro-electric	Other Electricity	Net Electricity Imports	Carbon Dioxide Emissions (Million metric tons of carbon)
Armenia	0.96	9.0%	48.4%	0.1%	25.6%	16.9%	0%	0%	0.8
Azerbaijan	0.55	56.5%	39.0%	0%	0%	4.2%	0%	0.4%	12.7
Georgia	0.16	31.9%	27.6%	0.1%	0%	42.4%	0%	-2.0%	1.6
Total/ weighted average	1.67	26.8%	43.3%	0.7%	14.7%	15.2%	0%	-1.6%	15.1

Source: Energy Information Administration
Note: percentages may not add up to 100% due to rounding.

Table 3. Energy Supply Indicators, Caucasus Region

Country	Proven Crude Oil Reserves, 1/1/02E (Million Barrels)	Natural Gas Reserves, 1/1/02E (Trillion Cubic Feet)	Coal Reserves, 1/1/01 (Million Short Tons)	Petroleum Production, 2001 (Thousand Barrels Per Day)	Natural Gas Production, 2000 (Billion Cubic Feet)	Coal Production, 2000 (Million Short Tons)	Electric Generating Capacity, 2000 (Gigawatts)	Crude Oil Refining Capacity, 1/1/02E (Thousand Barrels Per Day)
Armenia	0	0	minimal	0	0	.003	2.7	0
Azerbaijan	1,178	4.4	0	311	200	0	4.8	442
Georgia	35	0.3	minimal	2	2.1	.022	4.5	110
Total	1,213	4.7	minimal	313	202.1	.025	12.0	552

Source: Energy Information Administration

Sources for this report include: AFX-Asia, Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring Trans Caucasus Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian

Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, The Economist, The Financial Times, FSU Oil and Gas Monitor, Interfax News Agency, The International Herald Tribune, ITAR-TASS News Agency, The Moscow Times, Petroleum Economist, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, and World Markets Online.

LINKS

For more information from EIA on the Caucasus Region, please see:
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Caucasus Region

The Caucasus Region, comprising the newly independent states of Armenia, Azerbaijan, and Georgia, is important to world energy markets as a transit area for oil and natural gas exports from the Caspian Sea to Europe. Although the region has been beset by conflict, regional leaders hope that the development of several oil and natural gas export pipelines will bring peace and prosperity to the Caucasus.

Note: Information contained in this report is the best available as of March 2002 and is subject to change.

GENERAL BACKGROUND

The Caucasus region has been fought over by outside powers for centuries, but in 1991, Armenia, Azerbaijan, and Georgia received their independence from the Soviet Union. However, the Soviets bequeathed a number of problems on the three countries, including artificially drawn national borders and centrally-planned economies that were heavily dependent on Russia. Even before Azerbaijan and Armenia received independence, fighting broke out in 1988 between the then-Soviet republics over the disputed area of Nagorno-Karabakh, and separatist conflicts sparked in Georgia soon after independence. Although most of the regional conflicts that flared in different parts of the Caucasus throughout the 1990's are now dormant, none have been officially resolved.

Each of the Caucasus countries has experienced a severe economic downturn since the Soviet era. Conflicts in the region have discouraged foreign investment, and the lack of economic and political reform, along with the continuing hostilities between Azerbaijan and Armenia, have limited the region's economic growth. Although each of the countries is, to different degrees, trying to wean itself off dependency on Russia, Armenia, Azerbaijan, and Georgia remain economically linked to Russia.

Despite their geographical proximity, Armenia, Azerbaijan, and Georgia all have different strategies to diversify their energy suppliers and reduce their dependence on Russia. While Azerbaijan looks to the development of its domestic oil and natural gas reserves for an economic boom, Georgia is merely trying to keep electricity on for its citizens. Thus, Georgia is counting on transit oil and natural gas transit from the Caspian Sea region to boost its growth outlook: tariffs from transit oil pipelines will feed the government's budget, while fuel received from natural gas pipelines will fire Georgian electric-generating plants. Armenia, which is fighting a blockade by Azerbaijan and Turkey, does not figure to benefit substantially from the east-west pipelines that are in development, is cultivating closer ties with Iran in order to diversify its energy sources.

With a number of regional energy projects in development, Georgian President Eduard Shevardnadze expressed his hope that additional cooperation in the Caucasus will lead to greater trust and increased prosperity for the three countries. Until economic and political reforms take root, however, and a lasting peace is implemented, economic growth in the Caucasus likely will continue to lag behind other regions undergoing the transition from communism to democracy.

REGIONAL ENERGY ISSUES

The Caucasus region's energy importance stems from its location as a land bridge between the Caspian Sea and the Black Sea. Although the region itself does not have significant fossil fuel resources, except in the east of Azerbaijan, the Caucasus provides a link between the bountiful oil and natural gas reserves of the Caspian Sea region and the energy-hungry economies of Turkey and the European Union (EU).

The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk Road) was launched at a European Union (EU) conference in 1993, bringing together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an east-west axis. As oil and natural gas production in Central Asia and the Caspian region increase, the Caucasus has the potential to become a major transit center for oil and natural gas supplies heading west to world markets.

Oil Transit

With the collapse of the Soviet Union and the increase in oil production from the Caspian Sea region, the Caucasus region has gained in importance from an energy perspective. Previously, the only way for Caspian Sea region oil exports to reach European consumers was via the Russian pipeline system. The United States has supported the principle of multiple export options for Caspian exporters, and a number of Caspian region oil export pipelines are planned or already have been built. Many of these pipelines are routed via the Caucasus, and the region has become the central component of a European Union strategy to direct Caspian oil to European consumers.

Baku-Ceyhan Pipeline

In November 1999, Azerbaijan, Georgia, and Turkey signed agreements affirming the Baku-Ceyhan route as the Main Export Pipeline (MEP) for Azeri oil exports. The planned 1-million-bbl/d capacity pipeline, which has received backing from the United States, will run 281 miles through Azerbaijan, 135 miles through Georgia, and 622 miles through Turkey, and is expected to cost between $2.8 billion and $2.9 billion.

Despite initial opposition to the pipeline, which several oil companies criticized as too costly and uneconomical with the planned volumes from Azerbaijan, construction on the pipeline appears set to begin in the summer of 2002, with a planned launch date at the end of 2004. Detailed engineering work for the pipeline began in June 2001 and is slated to finish in June 2002, identifying a 50-yard-wide corridor through each of the three countries to lay the pipeline. Tenders have been announced to lay the pipeline in Georgia and Azerbaijan (Botas will lay the Turkish section of the pipeline).

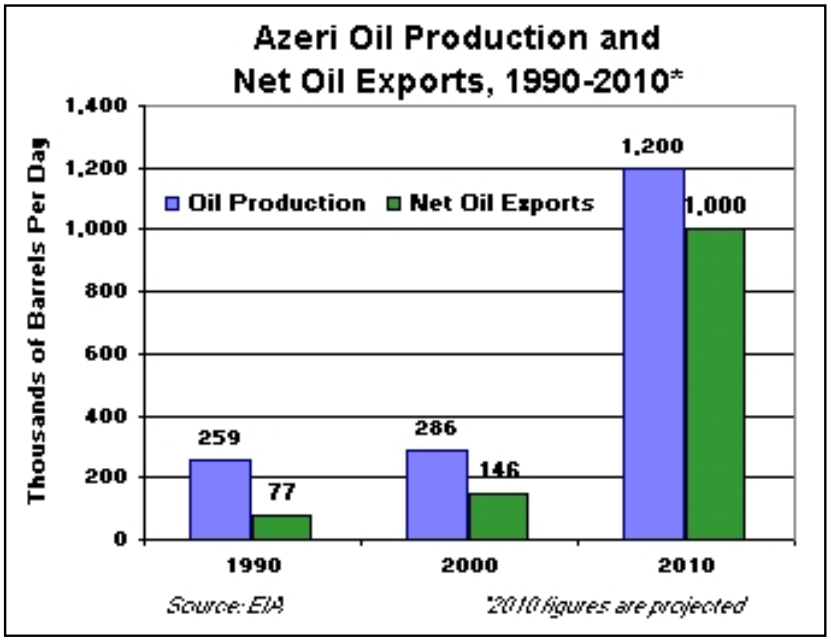
Baku-Supsa Pipeline

On March 8, 1996, Georgian President Eduard Shevardnadze and Azerbaijani President Heydar Aliyev signed a 30-year agreement to pump a portion of the Azerbaijan International Operating Company (AIOC)'s "early oil" via Georgia to its Black Sea port of Supsa. The Georgian International Oil Company, a subsidiary of the AIOC, made substantial upgrades to the existing 515-mile pipeline along this route and built the $565-million Supsa terminal on the Black Sea.

The so-called "western route", which became operational in April 1999, had an original design capacity of 100,000 bbl/d, but recent upgrades have raised capacity closer to 145,000 bbl/d. Officials from BP, the British-based operator of AIOC, said that the consortium exported approximately 130,000 bbl/d in 2001, with virtually all of its oil available for export being shipped to Supsa. The Baku-Supsa route, however, was designed to carry only the early oil from the AIOC's development of the Azeri-Chirag-Gunashli fields, and although there has been discussion of increasing the pipeline's capacity to 300,000 bbl/d or even 600,000 bbl/d, AIOC is planning to export its future production via the Baku-Ceyhan Main Export Pipeline, once it becomes operational.

Baku-Novorossiisk Pipeline

The 100,000-bbl/d-capacity Baku-Novorossiisk pipeline, also known as the "northern route", opened in 1997. The pipeline runs 868 miles from Baku via Chechnya to the Russian Black Sea port of Novorossiisk. Initial exports through the pipeline were limited to approximately 40,000 bbl/d, however, owing to pumping limitations, disputes over transit tariffs, and the conflict in Chechnya. Up to 70,000 bbl/d of oil was forced to bypass Chechnya by rail from Dagestan to Stavropol.



The ongoing conflict and instability in Chechnya prompted Russian pipeline operator Transneft to construct a 120,000-bbl/d Chechnya pipeline bypass (160,000 bbl/d including rail links). This bypass, which was completed in 2000, includes an 11-mile spur to Russia's Caspian Sea port of Makhachkala. The pipeline and spur could eventually transport up to 360,000 bbl/d of oil, enabling additional exports from Azerbaijan, Kazakhstan, and Turkmenistan to flow through the pipeline from Baku and Makhachkala.

In 2000, Azerbaijan's SOCAR committed itself to throughput of 46,000 bbl/d, but in the end only transported around 10,000 bbl/d, prompting Transneft to accuse Azerbaijan of not fulfilling its commitment to export oil along the bypass. The AIOC, which also was expected to export via Baku-Novorossiisk, has been reluctant to send its oil along this route because it is longer and more expensive than the Baku-Supsa route, and also because the northern route mixes AIOC crude with other crude oils while in transit to Novorossiisk, reducing its value.

SOCAR exported approximately 50,000 bbl/d via the Baku-Novorossiisk route in 2001, and plans to maintain that rate in 2002. Russia says the the capacity on Baku-Novorossiisk can be increased to 300,000 bbl/d, but SOCAR will not have sufficient volumes to fill the pipeline, even at its present capacity, in the next few years. Future Azeri oil production, mainly from the AIOC, is slated to be exported via the Baku-Ceyhan pipeline, although Transneft claims that exporting via the Baku-Novorossiisk pipeline would be cheaper.

Other Oil Transit

Prior to the opening of the CPC pipeline in the fall of 2001, ChevronTexaco had been delivering oil from the Tengiz field in Kazakhstan via the Caucasus. ChevronTexaco sent its oil across the Caspian by barge to the Dubendi terminal in Azerbaijan, where it was further transported via a pipeline to Ali-Bayramly (Azerbaijan), and then to Georgia's Black Sea port at Batumi in rail cars. In September 1999, Chevron (as it was then known) and Georgian company Geoengineering signed an agreement on the preparation of a feasibility study for the reconstruction of the Khashuri-Batumi, with an eye towards using the pipeline for transiting Tengiz crude. Together with an upgrade of

the Batumi refinery, the project was estimated to cost $100 million.

With the launch of the CPC, however, ChevronTexaco decided in May 2001 to cancel the project to reconstruct the Khashuri-Batumi pipeline, saying that the pipeline was economically unfeasible, especially since most of the Tengizchevroil exports are now routed via the CPC. Nevertheless, Tengiz crude has been replaced at the Batumi port by high-quality Kumkol crude, supplied by Euro Asian Trading, and the lower-quality Buzachi blend, produced by Kazakhstan's Mangistaumunaigaz, both of which reach Batumi via a combination of barge, pipeline, and rail across the Caspian and the Caucasus. Turkmenistan also exports occasional cargoes of Cheleken and Okarem crude, which are mostly blended with the Kazakh oil either at the Batumi terminal or on barges, forming a "synthetic Urals" blend.

Rail cars loaded with oil from Ali Bayramly are beginning to overwhelm the Georgian Black Sea ports. Although throughput at the Batumi terminal was 120,000 bbl/d in February 2002, with 400 tank cars per day offloaded, Azerbaijan was sending more than 500 tank cars per day, leaving over 100 tank cars per day unloaded. The backlog in offloading tank cars at the Georgian ports has led to a shortage of tank cars in Azerbaijan. In May 2001, the EBRD agreed to finance the construction of a $20-million oil terminal at the Black Sea port of Poti. The Poti terminal will be able to handle up to 50,000 bbl/d, proving an alternative to the main port at Batumi.

In addition, Georgia and Turkey are working on plans to utilize a 172-mile railway line between Tbilisi and Kars, Turkey, to transport up to 200,000 bbl/d of crude oil from the planned Baku-Ceyhan pipeline to Turkish refineries. The railway plan, which could cost $400 million, will require refurbishing an existing line from Tbilisi to Akhalkalaki for $200 million, as well as extending the rail line 77miles to Kars.

Natural Gas Transit

The Caucasus region also is set to become a major transport corridor for natural gas. Most of this will come from increased Caspian Sea region natural gas production, especially from Azerbaijan. As Azerbaijan begins to exploit the Shah Deniz natural gas field, which has estimated reserves of 35.3 trillion cubic feet (Tcf), its natural gas production will rise dramatically, and the country's March 2001 agreement with Turkey will allow Azerbaijan to boost its natural gas exports by piping Shah Deniz supplies via Georgia to Turkey. In addition, Armenia and Iran are developing a natural gas pipeline to connect the two countries, with the pipeline possibly continuing further northwards to connect to Georgia and then to the Russian pipeline system.

Baku-Erzurum Pipeline

On March 12, 2001, Azerbaijan and Turkey reached a natural gas export deal whereby Azerbaijan will supply Turkey with 3.1 trillion cubic feet (Tcf) of natural gas from 2004 through 2018. To deliver the natural gas to Turkey, BP, the operator of the Shah Deniz field, announced on March 14, 2001, plans to build a 1.06-Tcf-per-year-capacity pipeline from Baku to Erzurum, Turkey, via Georgia. Originally, Azerbaijan had hoped to use part of the existing Gazi-Magomed-Gazakh pipeline to transport the natural gas across Azerbaijan, but technical inspection of the pipeline deemed that costly repairs would first be necessary, and the huge volume of natural gas that Azerbaijan agreed to export--exceeding the capacity of the Gazi pipeline--necessitated that a new pipeline be built.

After lengthy negotiations that threatened to negate Azerbaijan's export deal with Turkey, in September 2001, Georgia and Azerbaijan cleared a major hurdle for the pipeline by signing a transit agreement. The agreement calls for Georgia to receive 5% of the natural gas in the pipeline, as well as preferential rights to purchase additional natural gas from the pipeline for 20 years, in exchange for transit rights. The Azeri parliament ratified the transit agreement in October 2001, followed by the Georgian parliament in December 2001. In January 2002, Georgian announced it will build two, 88.3-Bcf-capacity underground natural gas storage facilities in the east and southwest of the country as part of the pipeline project.

The Baku-Erzurum pipeline will stretch some 630 miles, including 290 miles in Azerbaijan and approximately 170 miles in both Georgia and Turkey. Detailed engineering for the pipeline, which will mirror the Baku-Ceyhan oil pipeline to Erzurum, is in progress, with tender proposals being prepared for construction of the Azeri and Georgian sections of the pipeline (Turkey's Botas will construct the Turkish section of the line). Currently, the pipeline project is estimated to cost $1 billion. Credits to be drawn from international financial institutions, including the World Bank, European Bank for Reconstruction and Development (EBRD), International Finance Corporation (IFC), and investors from the United States and Japan are expected to cover 70% of the pipeline's construction costs, while shareholders in the development of the Shah Deniz field development will contribute the remaining 30%.

Construction of the Baku-Erzurum pipeline is scheduled to begin in late 2002 and to be operational by the end of 2004. Initial capacity on the pipeline is slated to be 777 billion cubic feet (Bcf) per year, with capacity eventually rising to 1.06 Tcf per year. With natural gas production in the first stage of exploitation of the Shah Deniz field expected to be 282 Bcf per year, the Baku-Erzurum pipeline will have excess capacity to pipe additional Caspian Sea region natural gas exports, possibly from Turkmenistan if the Caspian littoral states agree on a legal regime for the Sea, allowing the proposed Trans-Caspian Gas Pipeline to be built. In addition, Turkey is in consultations with Greece to extend the Baku-Erzurum pipeline into the territory of the European Union.

Iran-Armenia Pipeline

Armenia and Iran are pushing ahead with a long-standing project to build an 84-mile natural gas pipeline linking the two countries. The pipeline project, dating back to intergovernmental agreements signed in 1992 and 1995, would allow Armenia to diversify and stabilize its natural gas supply sources, as well as expedite the closing of Armenia's Metsamor Nuclear Power Plant, which the European Union considers dangerous.

Implementation of the project has been delayed for years due to disagreements between the two sides over natural gas prices and the location of the pipeline. The original proposal was for the pipeline to be laid from northwestern Iran to the existing Armenian pipeline that terminates in Kadzharan, requiring the pipeline to transit the Azeri exclave of Nakhichevan. However, the still unresolved hostilities between Azerbaijan and Armenia over Nagorno-Karabakh made this plan impossible. In addition, Armenia balked at the high price of natural gas (from $84 to $90 per 1,000 cubic meters) that the Iranian side set for the pipeline.

Although the two sides have not been able to agree on a price for Iranian natural gas, in December 2001, Armenia and Iran signed a transit agreement to allow Armenia to import Turkmen natural gas via Iran. Turkmenistan is linked to the Iranian natural gas pipeline network through the Korpezehe-Kurt Kui pipeline, which opened in December 1997. The Iran-Armenia pipeline is now slated to cover 84 miles, running from Tabriz to Khadzaran and bypassing Nakhichevan. An initial feasibility study for the pipeline, with initial capacity of 35.3 Bcf and possibly up to 106 Bcf per year, has been completed.

The estimated cost of the Iran-Armenia pipeline is $120 million. The European Union has declared its readiness to assist in financing the pipeline's construction, but Gazprom and Itera, both of which previously expressed an interest in participating, announced that they would participate in the construction only through their partial ownership of Armrosgazprom, Armenia's natural gas distributor. France's Gaz de France previously announced its intention to invest in the pipeline, but has not committed to the project. Any significant investment in an Iranian oil project may be subject to the Iran and Libya Sanctions Act, which the U.S. Congress renewed in August 2001.

Once financing for the pipeline is secured, construction can commence. During the first stage of construction, which

Armenia hopes to begin in 2002, Armenia will lay a 24-mile pipeline section from Kadzharan to the southern border at Megri for approximately $26 million. Ukraine, which currently imports significant amount of Turkmen natural gas via Russia, has suggested that the Iran-Armenia pipeline be linked to its proposed route from Turkmenistan through Iran and Armenia. In addition, once the Iran-Armenia pipeline is completed, it will link the Iranian and Russian natural gas transportation systems, allowing for possible Iranian natural gas exports to Europe through the Russian pipeline system.

Other Natural Gas Transit in the Caucasus
In November 2000, Georgia approved a project for a 37-mile pipeline to carry Russian natural gas to Turkey via the Georgian Black Sea coast. After a September 2001 meeting, Georgian officials announced that representatives from Conoco and Turkey's Acsoy Group were ready to invest in the pipeline, which would transport 35.3 Bcf per year of natural gas from Kobuleti, Georgia, to Hopa, Turkey.

Georgia also has held discussions with Gazprom on refurbishing the existing North Caucasus-Transcaucasian natural gas pipeline and extending it into a trans-Georgian pipeline to bring Russian natural gas to Armenia and Turkey. However, this idea has lost some support as Russia focuses on delivering its gas to Turkey via the "Blue Stream" natural gas pipeline under the Black Sea.

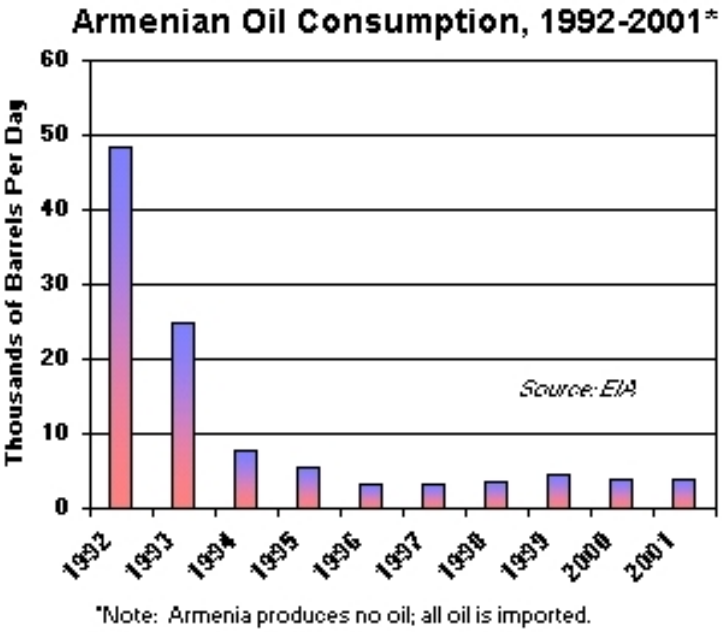
The Caucasus region may also serve as a transit region for liquefied natural gas (LNG). Conoco, together with the Acsoy Group, began a project to supply liquefied gas from Russia and the Caspian region to Turkey in 1999. However, the volume of natural gas supplies was small, and Conoco withdrew from the project. In September 2001, Batumi Oil Terminal Ltd., which owns the Batumi terminal, said that it would continue developing the project, where LNG will be barged from Kazakhstan and Turkmenistan across the Caspian to Baku, then transported using rail and sections of the natural gas pipelines in Georgia to Batumi. From there, the LNG will be sent to Turkey and other Mediterranean customers.

ARMENIA
Following a severe economic decline in the early 1990's, Armenia is continuing its slow recovery from the collapse of the Soviet Union and the effects of Armenia's six-year war with Azerbaijan over Nagorno-Karabakh. In 1994, Armenia launched an ambitious International Monetary Fund-sponsored economic program that has resulted in positive growth rates for the past eight years, despite the Azerbaijani-led economic blockade of Armenia.

Armenia's small- and medium-sized enterprises, most of which have already been privatized, have spurred continuing economic growth. The country's economy registered strong growth in 2001, with real gross domestic product (GDP) increasing 7.2%, up from 6% growth in 2000. Armenia's real GDP is forecast to grow by 5.4% in 2002. Inflation rose only slightly in 2001, to 3%, from 0.4% in 2000, and Armenia's unemployment rate dropped from 11.7% in 2000 to 10.5% in 2001. At its current growth rate, by 2005, Armenia's absolute GDP will reach the same level as in 1991, the year that the Soviet Union and its central economic planning system collapsed..

Oil
Armenia has no oil production, known reserves, or refineries, making the country completely dependent on imports of refined petroleum products. In addition, because there are no oil pipelines into Armenia, all of the country's petroleum products must be imported by rail or by truck. Since the end of subsidized oil supplies after the collapse of the Soviet Union, Armenia's oil consumption has dwindled from 48,400 barrels per day (bbl/d) in 1992 to just 4,000 bbl/d in 2001, most of which comes from the Batumi refinery in western Georgia.

Although the planned "Main Export Pipeline" (MEP) for Caspian region oil is not slated to transit Armenian territory, Armenian officials occasionally have spoken of potential cost savings if the MEP were built through northern Armenia, since it would shorten the export route considerably. However, the lack of a peace agreement between Armenia and Azerbaijan over Nagorno-Karabakh makes this idea extremely unlikely. Azerbaijani officials have dismissed the idea altogether, noting that the route through Georgia already has been decided.



Natural Gas

With no proven natural gas reserves, Armenia is reliant on imports to meet its domestic natural gas demand. In 2000, Armenia consumed 49.8 Bcf of natural gas. Since the Nagorno-Karabakh conflict erupted, Azerbaijan has ceased natural gas shipments into Armenia from the Soviet-era natural gas pipeline linking the two countries, forcing Armenia to import all of its natural gas via the Georgian and Russian natural gas pipeline networks to the north. The private natural gas trading company Itera has been Armenia's main natural gas supplier since 1996. The proposed Iran-Armenia natural gas pipeline will allow Armenia to diversify its natural gas suppliers, with Turkmen natural gas to be piped via the Iranian pipeline network to Armenia.

Natural gas in Armenia is distributed by Armrosgazprom, a closed joint-stock company owned by the Armenian government (45%), Russia's Gazprom (45%), and Itera (10%). Armrosgazprom planned to re-invest $6 million from its own funds in 2001 in an effort to rehabilitate Armenia's natural gas sector. In February 2001, Armenia and Russia reached an agreement on Armenia's $7-million debt for natural gas shipments dating back to 1999, which Itera supplied on Gazprom's behalf. Since Gazprom and Itera owed Armenia their contribution to the incorporation capital of Armrosgazprom, in July 2001, Itera agreed to write off Armenia's debt in exchange for the Armenian government transferring its natural gas pipelines to the joint enterprise towards Russia's share.

Armenia has continued to rack up natural gas debts to Itera, prompting the company to reduce supplies to Armenia in October 2001 to force payment. In late January 2002, Itera again threatened to reduce natural gas shipments to Armenia by two-thirds unless Armenia stayed current in its payment for supplies. In mid-February 2002, Itera announced that it had decided not to alter the level of natural gas supply to Armenia because the country honored a January 11, 2002, agreement to pay its debt for the natural gas acquired in 2001 and January 2002.

Coal

Armenia has no coal reserves or coal production. Armenia's coal consumption, most of which is used for home heating, totaled 3,307 short tons in 2000.

Electricity

Armenia's power sector has a total installed generating capacity of 2.7 gigawatts (GW). The country has two large thermal power plants--at Yerevan (550 megawatts, MW) and Hrazdan (1,110 MW)--as well as a smaller plant at Vanadzor (96 MW). Armenia also has significant hydroelectric power-generating ability and one nuclear power plant. In 2000, Armenia generated 5.7 billion kilowatt-hours (Bkwh) of electricity and consumed just 4.9 Bkwh, but since power is not provided to all regions of the country on a regular basis, the country's potential demand for electricity outpaces supply. In addition, the thermal plants have exceeded their projected operating lifespan, are in

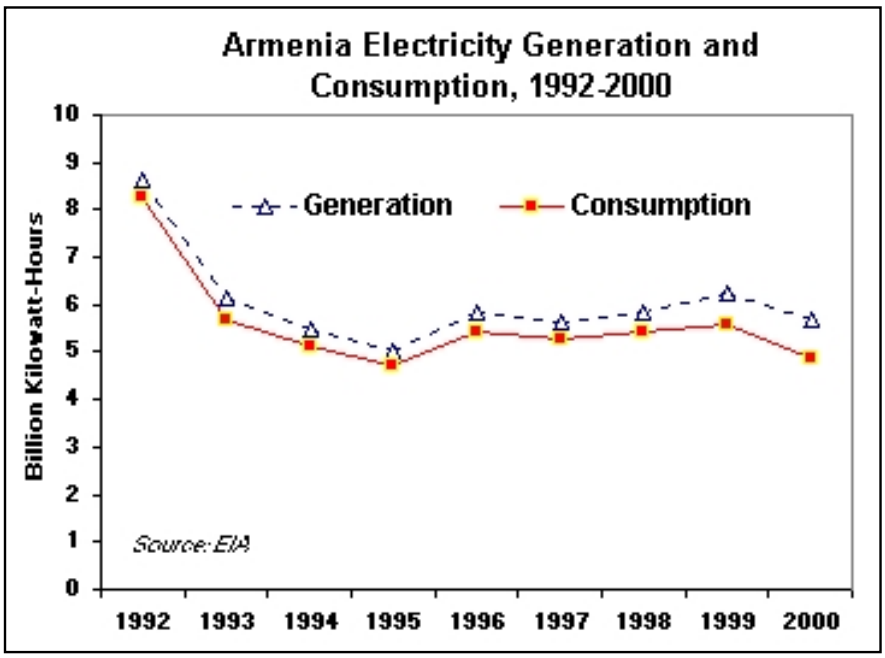
need of renovation, and are often low on fuel, since Armenia must import all of its natural gas.

Iran and Armenia already have linked their electricity grids, allowing for power sales in both directions driven by seasonal differences in demand between the two countries. In summer, Armenia exports its power to Iran and gets it back in winter. Armenia also supplies some of its surplus seasonal electricity to Georgia. Closer ties with Iran could give Armenia an additional source of electricity as Iran, Turkmenistan, and Armenia explore whether their power grids can be linked. Armenia could receive electricity from Turkmenistan via Iran's energy system at less than the price of power produced by its own power stations.

Privatization

In 1998, Armenia's parliament passed a law allowing for the sale of the country's electricity transmission and distribution networks, while keeping power generation under government control. In an effort to support Armenia's privatization efforts, on December 5, 2000, the European Bank for Reconstruction and Development (EBRD) signed an agreement with the Armenian government to take 20% equity stakes in each of the country's four electricity distribution companies: Yerevan, Northern, Southern, and Central. The agreement, which lasts for five years, includes a clause giving the Armenian government the right to buy back the EBRD shares should the agreement be abrogated.

U.S.-based AES Silk Road, ABB Energy Ventures of Sweden, and Spanish Union Fenosa Acex had been among the companies initially interested in the networks when the privatization tender was announced. However, the privatization process stalled in March 2001, when Armenian authorities announced they had not received any bids for the 75% stake in the first two distribution networks. In April 2001, the second stage of the tender also failed to attract any bidders. Armenia is now looking to implement additional needed reforms, including possibly unifying the distribution grids into one, before proceeding with another privatization tender for the distribution networks. In September 2001, Armenian Energy Minister Karen Galustian said that Russia's Unified Energy Systems, Gazprom, and Itera likely will participate in the eventual privatization.



Metsamor Nuclear Power Plant

Armenia has one nuclear power plant, the controversial Metsamor Nuclear Power Plant (NPP). The power plant, with two VVER-design reactors and a combined capacity of 815 MW, was shut down in March 1989 by the Soviet Union because of safety fears following the devastating earthquake that struck Armenia in December 1988.

However, faced with a deepening energy crisis due to the country's lack of fossil fuels and the economic blockade imposed by Azerbaijan and Turkey, on November 5, 1995, Armenia decided to resume operation at the 440-MW second unit. The plant, which was built in 1980 with a design life of 30 years, now supplies between 40% and 45% of the country's electricity.

Since the Metsamor NPP was inactive for six years, Armenian and Russian nuclear officials believe that the lone reactor functioning at the plant could operate through 2016. The European Union, however, is pressuring Armenia to shut the plant earlier, since the EU considers Metsamor to be a safety risk due to flaws in the plant's Soviet-designed

reactors and the region's seismic activity. In July 2001, Unit 2 at Metsamor was halted for planned maintenance and was supposed to be back in operation by the end of August, but debts delayed the reactor's launch: Armenia owed Russia $17 million for nuclear fuel already supplied, with the cost of new fuel set at $14 million. Armenia finally re-started the reactor in November 2001. Experts have estimated that required safety upgrades at the plant will cost about $1 billion over the next 15 years.

Rather than increasing spending to maintain the Metsamor NPP, the Armenian government has pledged to decommission the plant by 2004, provided the country has sufficient alternative energy sources by that time. The EU is pledging Armenia 100 million euros ($91 million) to build alternative power-generating facilities to replace Metsamor. However, Armenian Energy Minister Karen Galustian said that the country will need up to $1 billion from foreign investors and donor countries to safeguard Armenia's energy security after closing Metsamor.

Hydroelectric Power

Hydroelectricity accounted for almost 25% of Armenia's electric power generation in 2000. Armenia has several hydroelectric plants on the Hrazdan River, including the Sevan-Hrazdan hydroelectric plant, and has plans to develop several additional hydroelectric projects. Armenia is undertaking a program to construct 38 small and three large hydroelectric power plants, with an overall capacity of 296 MW. The cost of this program will be $300 million, part of which will be financed by the World Bank and the EBRD.

Of the three large hydropower plants, two--Lori Berd and Shnokh--will be built in the Armenian northeast, one with a capacity of 60 MW and an annual output of 192 million kilowatt-hours, and the other with a capacity of 75 MW and an annual output of 300 million kilowatt-hours. The third proposed hydropower plant, at Megri on the Araks river on the Armenian-Iranian border, is slated to have a capacity of 78.9 MW and to generate 469 million kilowatt-hours of electricity a year. Armenia and Iran have set up a joint company to construct the Megri hydroelectric power station, which will cost from $60 million to $80 million and take over five years to build. However, Azerbaijan has objected to the proposed plant, arguing that its Nakhichevan exclave will have its water supplies severely decreased if the Megri hydroelectric power station is constructed.

AZERBAIJAN

For detailed information on Azerbaijan's energy sector, visit the Azerbaijan Country Analysis Brief.

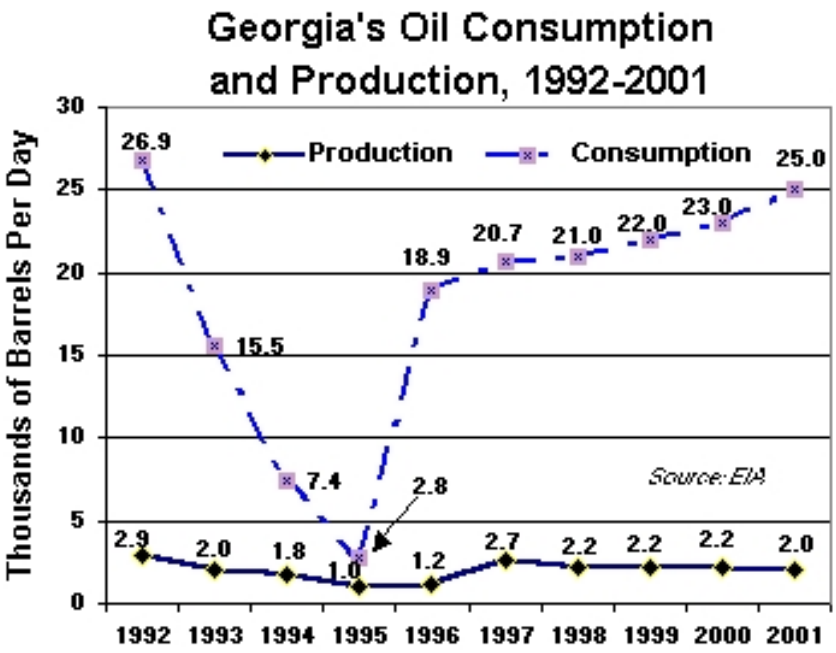
GEORGIA

More than ten years since Georgia's independence from the Soviet Union, the country continues to suffer from political turmoil, civil strife, and a weak economy. Although President Eduard Shevardnadze restored order following the overthrow of Georgia's first democratically elected president, separatist struggles in Abkhazia (northwest Georgia) and South Ossetia (north central Georgia), along with entrenched corruption, discouraged foreign investment throughout the 1990's. As a result, Georgia's economy, which was already reeling from the loss of Soviet subsidies after independence, suffered through bouts of hyperinflation and severe economic contraction--by 1995, Georgia's GDP dropped to 20% of 1990 levels.

Since the mid-1990s, however, Georgia has progressed slowly, bringing inflation under control, introducing a stable currency, and experiencing moderate economic growth. In 2001, Georgia's real GDP grew by 4%, and the country's economy is projected to grow by 3.2% in 2002. Georgia's agricultural sector rebounded in 2001 after a drought in the summer of 2000 had disastrous effects, both on food supplies and on the country's hydropower potential, Georgia's only sizable internal energy resource. Power generation continues to be a problem in Georgia, and the unresolved conflicts in Abkhazia and South Ossetia have strained Georgian-Russian relations, as well as hindered economic growth in the country.

Oil

Georgia's has limited oil reserves, with approximately 35 million barrels, and the country's small oil industry does not produce enough to meet domestic needs. In 2001, Georgia produced approximately 2,000 bbl/d of oil, far short of the 25,000 bbl/d of oil that that the country consumed. CanArgo-Georgia, also known as the Georgian-British Oil Company (GBOC), is Georgia's leading producer, with an average of 1,200 bbl/d of oil produced from the Ninotsminda field in 2001. Saknavtobi (Georgian Oil), the state oil company, produced just 120 bbl/d of oil in 2001. Georgia is expected to produce around 2,000 bbl/d in 2002.



As Georgia continues its recovery from civil strife in the mid-1990s, oil consumption is on the rise, but so is investment in the country's oil sector. According to the Georgian National Oil and Gas Regulating Agency, around $125 million has been invested in Georgia's oil production sector in the past five years. Georgian authorities have estimated that, between 2001 and 2005, an additional $453 million will be invested in oil and natural gas exploration and production in Georgia by nine joint ventures. The country is pinning its hopes on a dramatic increase in domestic oil production in order to meet rising demand in the next decade.

Active exploration is underway in Georgia, both along the Black Sea coast and onshore. The joint ventures are conducting operations in a number of blocks, including Ninotsminda, Manavi, Rustavi Kartli, Samgori, Patardzeuli, Mtiani Kakheti, Mirzaani, Taribana, Patara Shiraki, Nazvrebi, Supsa, Chaladidi, and Shromisubani. Saknavtobi and Anadarko (U.S.) have worked out a package of production-sharing agreements on the Black Sea shelf, where exploration engineers have discovered roughly 580 million tons of oil (4.25 billion barrels), including about 200 million tons (1.47 billion barrels) offshore.

Georgia has negotiated production-sharing agreements and joint ventures with a number of companies, including an agreement with the German company GWDF International to develop the Chaladidi, Supsa, and Shromisubani fields in western Georgia, and with Frontera Eastern Georgia, a Georgian-American joint venture, to develop the Taribana field in Kakhetia. According to a program developed by Saknavtobi based on investment projects currently being carried out by oil joint ventures in Georgia, the country could produce up to 4 million tons of oil between 2001 and 2005 (an average of 16,000 bbl/d).

Downstream/Refining

Georgia has two refineries, a 106,000-bbl/d refinery at Batumi, and a smaller, 4,000-bbl/d refinery at Sartichala, the Georgian-American Oil Refinery (GAOR). The Batumi refinery, however, currently is undergoing a $250-million modernization and expansion by Japan's Marubeni Corporation and the JGC Corporation, forcing Georgia to import over 90% of the petroleum products it consumes.

After sitting idle for much of 2001, the GAOR refinery, which was built in 1998 and is owned by Canadian CanArgo (51%), Saknavtobi (28%) and GBOC (21%), ramped up operation in July 2001, processing about 8,000 tons of crude

oil (an average of 1,928 bbl/d for the month) into gasoline, diesel and fuel oil. However, difficulties in selling the gasoline, as well as the plant's less than 50% utilization rate, forced management to begin to shut down the facility again in August 2001. In September 2001, CanArgo announced it was closing the GAOR refinery, saying that prices for crude oil and the saturation of the domestic market with cheap oil products from Azerbaijan and Russia had made operation of the small refinery unprofitable.

Rather than continuing operations at the GAOR refinery, CanArgo announced plans to build a larger refinery at the same site. The Canadian company announced it would build a $200-million refinery that would be able to process up to 1.5 million tons of crude oil per year (30,100 bbl/d). Additionally, Switzerland's National Petroleum Limited (NPL), which has been developing Georgia's biggest oil field with Sakvnavtobi since 1996, revealed plans in July 2001 to construct a 40,000-bbl/d refinery in Georgia in the next few years. Georgia also has awarded Frontera the right to construct a new refinery near Tbilisi as part of its production-sharing agreement.

Natural Gas

Georgia has approximately 300 Bcf in natural gas reserves, and during Soviet times the country did not produce any natural gas. Since Georgia became independent in 1991 and stopped receiving subsidized fuel, the country's natural gas consumption has plummeted, from 177 Bcf in 1992 to just 42.7 Bcf in 2000. Although the country's natural gas sector increased output from zero in 1997 to 2.1 Bcf in 2000, Georgia remains heavily dependent on foreign suppliers to meet its domestic demand.

In addition, Georgia's inability to pay its suppliers has limited the country's consumption, as both Russia and Turkmenistan at times have cut off natural gas supplies to Georgia due to payment arrears. Turkmenistan has left the Georgian natural gas market, claiming that Georgia still owes it for past supplies, leaving Russia as the country's sole supplier. Itera, the Gazprom-affiliated natural gas trader, has been supplying Georgia for the past year, but the company repeatedly has reduced supplies to Tbilisi in order to force Georgia to pay its bills. As of December 2001, Georgia owed Itera about $90 million for previous natural gas supplies, prompting Itera to require prepayment for natural gas shipments to Georgia after January 1, 2002.

Georgian leaders hope to decrease this reliance on natural gas imports in coming years by courting foreign investors to develop the country's natural gas deposits and by reforming the country's natural gas distribution system. However, to date, there has been little interest among international energy companies in Georgia's natural gas production potential, and attempts to private Tbilgaz, the municipal natural gas distribution company serving Georgia's capital, have failed repeatedly. In June 2001, Georgia once again offered an international tender for an 85% stake in the Tbilisi distribution network. With the network only 25% operational, no bids were received.

Energy companies have had more interest in Georgia's natural gas transmission sector, mainly due to the country's burgeoning role as a transit center for natural gas exports from Azerbaijan. The Georgian International Gas Corp., which runs the country's transmission system, has been working on a program to modernize Georgia's internal natural gas pipelines, which stretch over 6,000 miles, in order to pump Azeri natural gas via Georgia for the planned Baku-Erzurum pipeline. In October 2001, the Georgian International Gas Corp. and Russia's Gazprom joined forces to create Gruzrosgazprom, a joint venture that will develop and operate the natural gas transport system in Georgia. The Georgian International Gas Corp. owns 51% of the joint venture.

With Azerbaijan's October 2001 decision to rehabilitate a 23-mile pipeline to the Georgian border, Georgia will be able to import between 7 Bcf and 10.5 Bcf of natural gas from Azerbaijan in 2002. Additionally, the natural gas transit agreement signed by the two countries in September 2001 stipulates that Georgia will receive 5% of the natural gas shipped via the Baku-Erzurum pipeline when it comes online in 2004. Under the transit agreement,

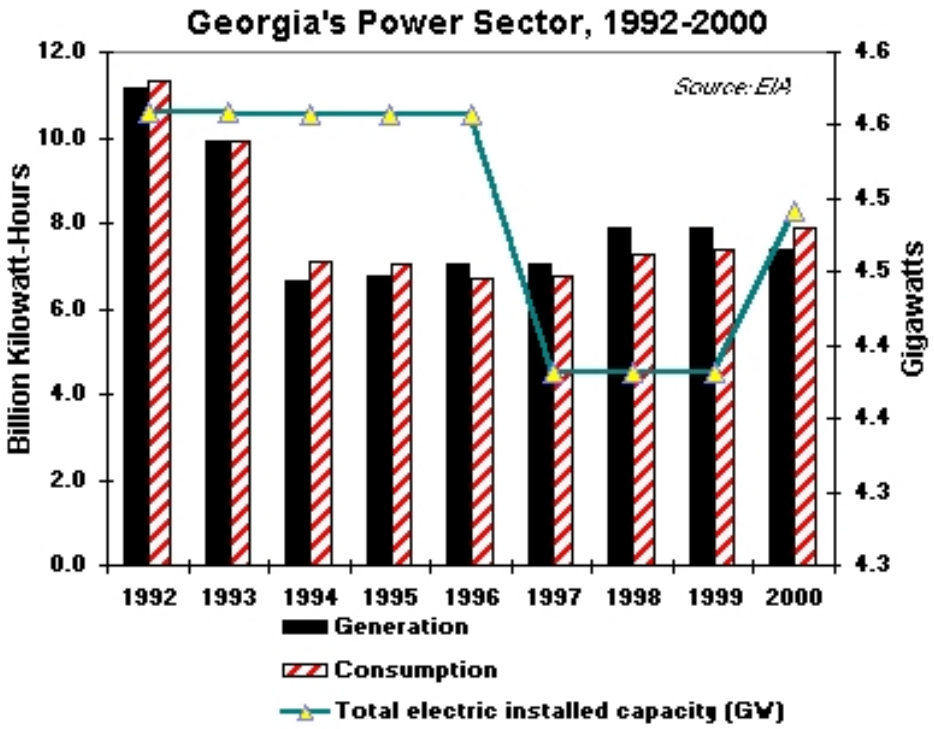
Georgia also will have the right to purchase 500 million cubic meters (17.7 Bcf) of natural gas per year for 20 years at a cost of $55 per 1,000 cubic meters (35,300 cubic feet).

Coal

Georgia's coal output, already low by world standards in 1991 when the country became independent, has decreased in the past decade. Between 1992 and 1997, the country's coal production declined from 220,462 short tons to 5,952 short tons--a drastic 97% reduction--although production has rebounded slightly, to 22,046 short tons in 2000. Similarly, Georgia's coal consumption plummeted 95% from 1992 to 1997, from 480,607 short tons to just 22,000 short tons, before climbing back to 37,479 short tons in 2000.

Electricity

Georgia's energy system includes about 60,000 miles of transmission lines, 53 hydroelectric power stations, and three thermal power plants, for an overall generating capacity of 4.5 GW. However, fuel shortages and aging power plants means that the sector is only able to operate at 40% of capacity. Georgia consumed more electricity than it generated in 2000: 7.9 Bkwh consumed compared to 7.4 Bkwh generated. In addition, because of inefficient and deteriorating power lines, power outages are a daily occurrence in much of the country, and parts of Georgia do not receive any electricity at all.



Georgia's total electricity demands have been estimated at nearly twice the amount that is actually generated, and the Georgian Energy Ministry estimates that 40% of all power that is generated is wasted due to equipment and maintenance problems in the transmission sector. To meet some of its power needs, Georgia imports electricity from Armenia, Azerbaijan, and Russia. Georgia has run up large electricity debts to each of the countries. In addition, because Georgia's natural gas supplies frequently are cut off due to the country's payment arrears, Georgia's own natural gas-fired power plants are often short of fuel. As a result, electricity supplies, even to Tbilisi, are erratic, leaving customers in the dark for 20 hours (or more) per day. Consumers, who use kerosene for heating, have responded to rate increases and inadequate power supplies by refusing to pay their electricity bills.

Privatization

The significant problems in Georgia's power sector have hampered the country's economic growth, making energy sector reform a government priority in 2002. In a January 2002 meeting with IMF representatives, Georgian Minister of State Avtandil Jorbenadze said that problems in the energy sector had been caused by rampant corruption and that the process of dealing with them should start with the establishment of a proper wholesale market, the speeding up of privatization of energy sector installations, and the drawing up of clear mechanisms for repayment of the energy sector's internal and external debts.

In an effort to resolve the problems in the power sector, Georgia is trying to reform and privatize Sakenergo, the state energy and power company. With support from the World Bank and the EBRD, most of Georgia's hydro and thermal generation units have been restructured as joint-stock companies, and the Georgian Ministry for the Management of

State Property is proceeding with privatization of energy distribution companies. In January 1999, AES (U.S.) purchased a 75% stake in the Telasi electricity distribution company, which serves the Tbilisi area, for $25.5 million. As part of the privatization agreement, AES made a made a further commitment to pay $10 million of Telasi's debt and $80 million in investment to provide consumers with 24-hour electricity.

Power Outages

Although Telasi's debts have stopped growing since AES took it over, AES has not been able to meet its pledge to provide 24-hour electricity because the company continues to receive erratic power supplies from power-generating companies. In addition to the inherent problems of Georgia's power sector, faltering equipment and sabotage by secessionist rebels also have led to power outages across Georgia.

On December 22, 2001, the Unit 10 at the Tbilisi Power Plant exploded, causing severe damage that will take at least a year to restore. AES-Mtkvari, a subsidiary of AES-Telasi that operates the 300-MW generating unit, said that the explosion occurred because the computer control system and the mechanical portion were incompatible. However, in January 2002, Georgia's national energy regulatory commission suspended AES-Mtkvari's license to operate the unit, prompting an AES Vice President to announce that the company will evaluate in the summer of 2002 whether it will remain in Georgia. AES-Mtkvari has owned the two most powerful (300 MW each) power-generating units at the Tbilisi Power Plant since the spring of 2000.

On January 2, 2002, an accident with an electricity transmission line brought electricity supplies to Georgia from Russia and Armenia to a halt. The Kavkasioni high-voltage electricity line, which supplies electricity from Russia to Georgia through regions high in the mountains, broke down for unknown reasons, but the stoppage of supplies from Russia and Armenia had an immediate impact on Georgia's provision of electricity, which was already struggling after the explosion at the Tbilisi Power Plant. After the December incident, Russia increased power supplies to Georgia via the Kavkasioni line. Georgian authorities did not rule out sabotage in the Kavkasioni incident, noting that in November 2001 secessionist rebels destroyed a bridge over the Pankisi Gorge near the Khador Hydroelectric Power Plant.

Hydropower Projects

Georgia is seeking foreign equity participation for both new capacity and rehabilitation hydropower projects. Hydropower accounts for 80% of Georgia's electricity generation, and the country has a substantial amount of untapped hydroelectric potential that could be exploited. Georgia already has made plans to build two new hydroelectric plants on the Rioni River (the 250-MW Namakhvani and the 100-MW Zhoneti), and the country is also hoping to build the proposed 40-MW Minadze station on the Kura river.

In February 2001, Chinese and Georgian officials signed an agreement on the construction of the 24-MW Khador Hydroelectric Power Plant near the Georgian-Russian border in the eastern Kakheti region. In September 2001, the Georgian-Chinese *Energokorporatsia Vostoka* company opened the first phase of the Khador cascade of mini hydroelectric plants. The first mini hydroelectric plant has capacity of 2 MW, and the entire facility will be launched by the end of 2002. Chinese investment in the project totaled $27 million.

In January 2002, Georgian Energy Minister David Mirtskhulava said that China's Sichuan Machinery, which is constructing the Khador Hydroelectric Plant, will invest $10 million in a second hydroelectric station in Georgia. The 9.3-MW plant will be built on the Chelta River in the Kakheti region. According to Mirtskhulava, construction of another hydroelectric plant in Kakheti would end the serious power shortages in the region, which is one of Georgia's biggest agricultural regions.

In addition, in November 2000, Georgia announced a tender for the rehabilitation of the existing Inguri Hydropower Plant, the country's largest. The project, which will cost an estimated $62 million, will boost the station's capacity from its current capacity of 400-450 MW, to 1,300 MW. The EBRD will provide $39 million in the form of a long-term credit, while the EU and Japan will give grants totaling $10 million. Georgia will finance the remaining $13 million.

Table 1. Economic and Demographic Indicators for the Caucasus Region

Country	Gross Domestic Product (Nominal GDP), 2001E (Billions of U.S. $)	Real GDP Growth Rate, 2001 Estimate	Real GDP Growth Rate, 2002 Projection	Per Capita GDP, 2001E	Population 2001E (Millions)
Armenia	$2.1	7.2%	5.4%	$542	3.8
Azerbaijan	$5.2	7.5%	7.0%	$646	8.1
Georgia	$3.1	4.0%	3.2%	$619	5.0
Total/weighted average	$10.4	6.4%	5.5%	$615	16.9

Source: DRI/WEFA

Table 2. Energy Consumption and Carbon Dioxide Emissions in the Caucasus Region, 1999

Country	Total Energy Consumption (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Electricity	Net Electricity Imports	Carbon Dioxide Emissions (Million metric tons of carbon)
Armenia	0.96	9.0%	48.4%	0.1%	25.6%	16.9%	0%	0%	0.8
Azerbaijan	0.55	56.5%	39.0%	0%	0%	4.2%	0%	0.4%	12.7
Georgia	0.16	31.9%	27.6%	0.1%	0%	42.4%	0%	-2.0%	1.6
Total/ weighted average	1.67	26.8%	43.3%	0.7%	14.7%	15.2%	0%	-1.6%	15.1

Source: Energy Information Administration
Note: percentages may not add up to 100% due to rounding.

Table 3. Energy Supply Indicators, Caucasus Region

Country	Proven Crude Oil Reserves, 1/1/02E (Million Barrels)	Natural Gas Reserves, 1/1/02E (Trillion Cubic Feet)	Coal Reserves, 1/1/01 (Million Short Tons)	Petroleum Production, 2001 (Thousand Barrels Per Day)	Natural Gas Production, 2000 (Billion Cubic Feet)	Coal Production, 2000 (Million Short Tons)	Electric Generating Capacity, 2000 (Gigawatts)	Crude Oil Refining Capacity, 1/1/02E (Thousand Barrels Per Day)
Armenia	0	0	minimal	0	0	.003	2.7	0
Azerbaijan	1,178	4.4	0	311	200	0	4.8	442
Georgia	35	0.3	minimal	2	2.1	.022	4.5	110
Total	1,213	4.7	minimal	313	202.1	.025	12.0	552

Source: Energy Information Administration

Sources for this report include: AFX-Asia, Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring Trans Caucasus Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, The Economist, The Financial Times, FSU Oil and Gas Monitor, Interfax News Agency, The International Herald Tribune, ITAR-TASS News Agency, The Moscow Times, Petroleum Economist, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, and World Markets Online.

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April 2002

Russia

Russia is important to world energy markets because it holds the world's largest natural gas reserves, the second largest coal reserves, and the eighth largest oil reserves. Russia is also the world's largest exporter of natural gas, one of the largest oil exporters, and the third largest energy consumer.

Note: Information contained in this report is the best available as of April 2002 and is subject to change.

GENERAL BACKGROUND

After a banner year in 2000, when Russia's real gross domestic product (GDP) grew by 8.3%, Russia's economic growth slowed in 2001. Nevertheless, Russia's economy grew by a healthy 5.1%, and the country's economy is in the best shape it has been in since the breakup of the Soviet Union in 1991. Russia's rate of inflation slowed from 20.2% in 2000 to 18.5% in 2001, and Russia's currency, the ruble, continued to strengthen in 2001, prolonging its remarkable rebound from the country's August 1998 financial crisis and devaluation.

Since energy accounts for approximately 40% of Russia's exports and 13% of the country's real GDP, Russia's economy is extremely sensitive to global energy price fluctuations. As a result, the decline in world oil prices in 2001 put the brakes on Russia's economic recovery, which was fueled by high world oil prices in 1999-2000 and the increased competitiveness of Russian exports in the aftermath of the 1998 financial crisis. Although the windfall in oil export revenues in 1999-2000 stimulated increases in other industrial sectors and helped the Russian government pay down some of its $154 billion foreign debt, structural reforms slowed in the euphoria of the oil revenues.

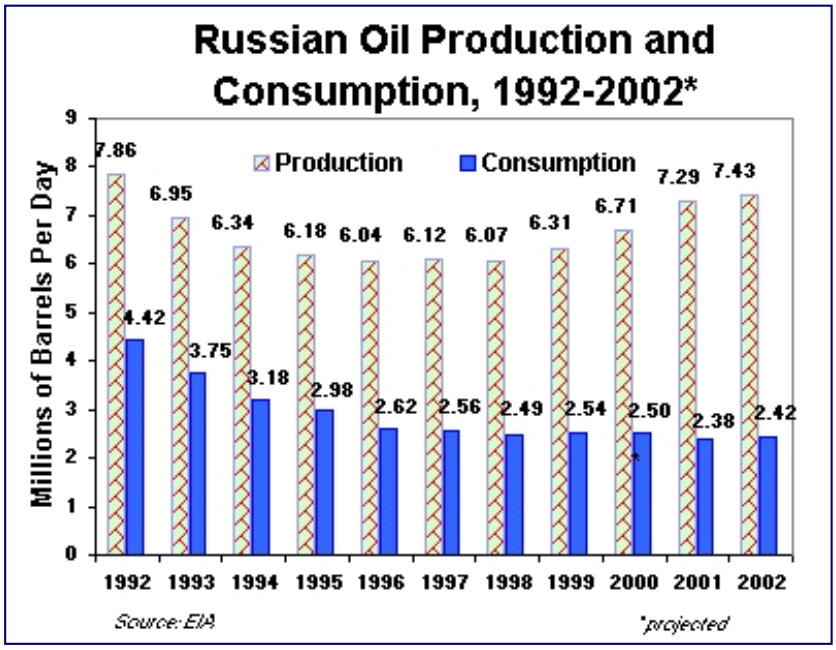
The drop in world oil prices after September 11, 2001, resulted in members of the Organization of Petroleum Exporting Countries (OPEC) requesting Russia and other non-OPEC members to cut their oil exports in order to boost prices. Russia agreed with OPEC in December 2001 to cut its oil exports by 150,000 bbl/d during the first quarter of 2002. Despite heavy lobbying by Russian oil companies to end the cut and to increase exports, Russia, whose state budget for 2002 is based on an average oil price of $23 per barrel and a minimum price of $18 per barrel, decided in March 2002 to continue its self-imposed cuts by 150,000 bbl/d through June 2002.

Although reforms have been slow in coming, restructuring and liberalizing the energy sector and making the Russian economy less dependent on oil and natural gas exports is a stated priority for Russian President

Vladimir Putin and the Russian government. Plans to break up the monopoly positions of both Gazprom and Unified Energy Systems, the Russian natural gas and electricity monopolies, have been approved. Similarly, the Russian government has pledged to improve the investment climate in Russia, but Russia's unstable tax and legal codes have kept many foreign energy companies from investing in Russia's energy sector. Russia has plans for a number of new oil and natural gas pipelines, and massive infrastructure investments will be needed to develop several planned international oil and gas projects.

OIL

After several years of production declines following the collapse of the Soviet Union, Russia's oil industry has bounced back over the past few years, posting strong profits and healthy increases in production. Russia is one of the world's biggest oil producers, but from 1992 to 1998, the country's oil production plummeted 23% due to decreased domestic industrial demand and a decline in drilling and capital investment.



Buoyed by high world oil prices in 1999-2000, Russian oil companies reinvested much of their generous profits into ramping up crude production. Since 1998, when production bottomed out at 6.07 million bbl/d, Russia's oil production, including condensates, has increased 20%, with overall production of 7.29 million bbl/d in 2001.

Despite Russia's pledge to OPEC to shave 150,000 bbl/d off its oil exports in the first half of 2002, Russian oil production is still forecast to post a 1.9% year-on-year increase--reaching 7.43 million bbl/d--in 2002. Russian oil production actually increased in the first few months of 2002, with average oil production of 7.49 million bbl/d in February 2002. Although Russian government officials have attempted to limit the country's oil exports, new export channels, such as the Baltic Pipeline System, have provided a powerful disincentive to Russian oil producers to reduce their output. As a result of Saudi Arabia's OPEC-mandated production cut (and that country's better compliance with its pledged cuts), Russia's oil production surpassed Saudi Arabia's in February 2002 for the first time since the Soviet era, making Russia the world's leading oil producer, if only temporarily.

Russia has proven oil reserves of 48.6 billion barrels, but aging equipment and poorly developed fields are making it difficult to develop these reserves. In addition, Russia's rate of oil production is exceeding its rate of discovery of new reserves by a significant margin. The Russian oil industry faces the depletion of existing oilfields, deterioration in transport infrastructure, and an acute shortage of investment due to the confusing tax and legal environment. In order to sustain and to increase Russia's oil production from current levels, large amounts of capital will be needed to develop new fields and to extend the life of existing oilfields with exhausted and low-yield reserves.

However, the sharp rise in oil prices during 1999-2000 provided Russian oil companies with a windfall in revenues, and many have begun to upgrade decaying oil infrastructure and to undertake new exploratory drilling. In addition to further development of the West Siberia region, where most of Russia's oil comes from currently, Russian oil producers are conducting more exploration in the Russian sector of the Caspian Sea, and teaming up with foreign oil producers to develop oil projects in the Arctic region, Eastern Siberia, and Sakhalin Island in Russia's Far East. Russia's future level of oil production will be defined by the

ability of oil companies to develop these new deposits, which will require a massive amount of infrastructure investment (including new export pipelines) in order to deliver this oil to customers.

Oil Sector Reform

Russia reorganized its state-run oil industry into a number of vertically-integrated oil companies in the early 1990s, and the state has divested itself of large stakes in most of these companies. Nonetheless, foreign investment in the industry has been minimal due to economic and political instability, a poor record of corporate governance, and the unstable legislative framework.

In order to create a more stable investment climate, potential investors have called upon the Russian government to undertake further reform, including the establishment of cohesive production-sharing agreement (PSA) framework legislation. Although the political and economic situation has stabilized since the August 1998 financial crisis, and high world oil prices in 1999-2000 enticed some investors into Russia, others are still awaiting the passage of a new Russian PSA regime and tax code.

Oil Exports

Despite problems surrounding the transition to a market economy and the lack of foreign investment in its oil sector, Russia remains one of the world's top oil exporters. After Russian oil exports slumped in the mid-1990s, exports rebounded after the ruble devaluation of August 1998 reduced production costs sharply for Russian oil producers, and the climb in world oil prices in 1999-2000 made exports even more profitable for Russian oil companies. With domestic consumption of 2.38 million bbl/d in 2001, Russia's increased its net oil exports in 2001 to 4.91 million bbl/d, making Russia the world's second largest oil exporter, behind only Saudi Arabia.

Russia is not a member of OPEC, but in recent years it has frequently attempted to coordinate its export strategy with OPEC. Although Russia agreed to reduce its oil exports by 150,000 bbl/d in the first quarter of 2002, Russian oil companies' compliance with these export cuts has been questionable at best, with preliminary data showing that Russian crude oil exports actually increased during the first quarter of 2002. Russian government officials levied higher export tariffs and set crude oil export quotas in order to limit the country's oil exports, but Russian oil companies increased their oil product exports instead. For 2002 as a whole, Russia's net oil exports are projected to increase to 5.01 million bb/d.

Oil Pipelines

Russia's oil exports could be even higher if they were not restricted by a lack of spare capacity in existing export pipelines. Despite Russia's pledged export cuts, the country's main export pipeline, the 1.2-million-bbl/d-capacity Druzhba pipeline, still is operating close to its highest capacity in years. In addition, many of the country's oil pipelines are in a state of disrepair, and Russian Energy Ministry figures indicate that almost 5% of crude oil produced in Russia is lost through illegal tapping of Russia's pipelines.

With a windfall in oil export tariffs in the past several years, Transneft, the state oil transport monopoly, has taken steps to upgrade the country's pipeline system, with an emphasis on building new export pipelines to increase and diversify export routes for oil exporters. In addition to constructing the Baltic Pipeline System and a possible pipeline to China, Transneft is seeking to lure additional transit oil from Azerbaijan, Kazakhstan, and Turkmenistan.

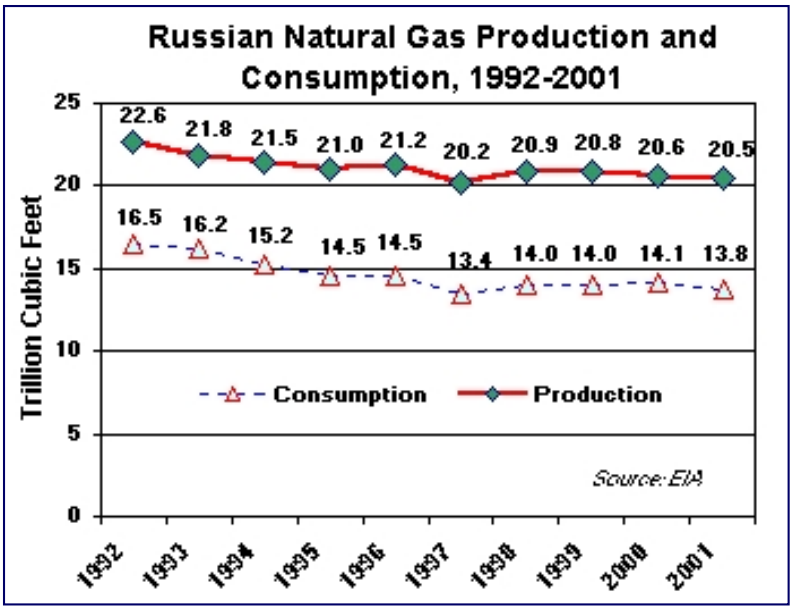
Downstream/Refining

Russia has 42 oil refineries--many of which are inefficient, aging, and in need of modernization--with a total processing capacity of 6.9 million bbl/d. With Russian domestic demand of 2.38 million bbl/d in 2001, refining capacity far outstrips demand for refined products. In addition, because a barrel of crude oil on the Russian market typically sells for just over half the world crude oil price, many Russian oil companies prefer to export their crude oil rather than to refine it in Russia. When Russian oil producers do not export their crude oil--often because of the constraints of Russia's pipeline system or the government's limits on each company's exports--many choose to supply their own refineries rather than sell the oil on the open market.

Russia's decision to go along with OPEC oil supply cuts in the winter of 2001-2002 has led to a glut of oil on the Russian market. As a result, Russian oil companies have channeled more oil into domestic refineries, and with refineries awash in crude, the domestic crude price collapsed, falling from about $13.70 per barrel at the wellhead in November 2001 to just $4.48 per barrel in January 2002. With many Russian refineries undergoing renovations or efficiency upgrades, Russia's refineries have not been able to handle so much crude oil at once. Preliminary data indicates that Russia's exports of refined products increased in the first quarter of 2002, and surplus refined products such as fuel oil, gasoline, and kerosene went into storage.

NATURAL GAS

Russia contains over 1,700 trillion cubic feet (Tcf) in proven reserves of natural gas, the world's largest. Gazprom, the state-run natural gas monopoly, produces nearly 94% of Russia's natural gas, operates the country's 90,000-mile natural gas pipeline grid and 43 compressor stations, and holds nearly one-third of the world's natural gas reserves while employing approximately 38,000 people. Often referred to as a "state within a state," Gazprom also is Russia's largest earner of hard currency, and the company's tax payments account for around 25% of federal government tax revenues.



Russia's natural gas production also is the largest in the world. Natural gas also accounts for over 54% of Russia's energy consumption, but the country still has plenty of natural gas available for export. According to Russia's State Statistics Committee, in 2001 Russia consumed 13.8 Tcf of natural gas while it produced 20.5 Tcf. With 6.7 Tcf in net natural gas exports, Russia is the world's largest natural gas exporter. In 2002, Russia is planning to increase natural gas production to 21.2 Tcf, while the country projects domestic natural gas consumption to increase to 14.6 Tcf.

In addition to its main producing areas in the Yamal-Nenets region of northern West Siberia at the Urengoy and Yamburg fields, Gazprom is responsible for future development of giant Bovanenkovskoye field on the Yamal Peninsula and other fields in the Yamal-Nenets region, including the the giant Pestsovoye and Zapolyarnoye fields to the north in the Ob-Taz Gulf area. Through its subsidiary Rosshelf, Gazprom also is responsible for development of the Shtokmanskoye field in the Barents Sea and other fields in the North Caucasus, Precaspian, Timan-Pechora, and the Volga-Urals.

Many analysts doubt Russia's ability to raise its natural gas production in the face of Gazprom's declining budget and the low levels of investment to the sector in recent years. Although Russia's natural gas sector has not been as hard hit as other sectors of the energy industry during the transition to a market economy (production is down just 9% since 1992), low investment in the sector has raised concerns about future production levels. Production in the Urengoy and Yamburg natural gas fields is declining, while the planned development of new fields continues to be delayed as a result of lack of investment resources. In February 2002, Gazprom scaled back its 2002 investment program for field exploration to $453 million from the $499 million invested in 2001.

Sectoral Problems

According to the Russian Gas Law of 1999, Gazprom must supply the Russian natural gas market, regardless of profitability, at regulated prices. Thus, the company is forced by the Russian government to

sell natural gas to domestic users for approximately $16 per 1,000 cubic meters (35,300 cubic feet)--less than it costs the company to produce, and only about one-tenth of the export price of $140-$150 per 1,000 cubic meters.

In addition, Gazprom continues to be hurt by chronic non-payments by consumers (although this situation has improved recently). In 1999, Russian consumers paid only 39% of their bills for natural gas in cash, but by 2001, Gazprom was paid in cash for 83% of the natural gas it sold domestically. Still, only 29 of Russia's 89 regions are up to date with their natural gas payments, and the multi-billion dollar debt of domestic natural gas consumers has hindered Gazprom's ability to invest adequately in new fields, many of which need major infrastructure investments.

The only investment in new natural gas production that Gazprom has made recently is the development of Zapolyarnoye, which was brought onstream in October 2001 to offset the decline in the company's production. Although Gazprom has enough undeveloped natural gas reserves in its portfolio to ensure future supplies, Zapolyarnoye is the last of the so-called "easy-to-develop" giant fields. Development of future fields, most of which are located in the more remote regions that lack infrastructure to deliver the natural gas to consumers, will require much higher levels of investment. Developments like Prirazlomnoye and Shtokmanskoye are provisionally budgeted to cost $1 billion and $15 billion to $20 billion, respectively.

Restructuring the Natural Gas Sector

While Gazprom is looking to establish partnerships with foreign investors to develop several natural gas production projects, restrictions on foreign investment in the company, along with allegations of asset stripping by senior managers of Gazprom, has limited Russia's investments in new natural gas developments. In addition, Gazprom's control over Russia's natural gas trunk-line system, forcing other producers to sell their natural gas to Gazprom on its terms, has proven a disincentive to increased natural gas production. The lack of access to Russia's natural gas pipelines has meant that Russian oil companies prefer to flare their associated natural gas instead of treating it and selling it to Gazprom.

In an attempt to spur increased investment in the industry and to raise production levels, President Putin is taking steps to end Gazprom's monopoly position and to restructure the natural gas sector. On November 9, 2000, the government ordered Gazprom to give other companies the right to use up to 15% of its pipeline capacity, and in May 2001, Gazprom's Board of Directors ousted long-time chief Rem Vyakhirev and replaced him with Aleksei Miller, an ally of Putin.

A restructuring plan currently under consideration would break Gazprom's upstream operations into separate producing companies in order to foster competition on the Russian domestic market, while the government would take control of Gazprom's transmission pipelines, offering equal access to all natural gas producers, thereby giving incentive to Russia's oil companies to treat the associated natural gas they develop. In addition, the Russian government is paying heed to Gazprom's minority shareholders, curtailing Gazprom's mysterious relationship with natural gas trader Itera and attempting to loosen restrictions on the purchasing of Gazprom shares by foreign investors.

Natural Gas Exports

The Russian government's determination to keep domestic natural gas prices artificially low means that the country's natural gas industry is heavily dependent on exports to finance its production. In 2001, Russia totaled 6.7 Tcf of net natural gas exports, the majority of which were piped to customers outside the Commonwealth of Independent States (CIS). Gazprom supplies Europe with 25% of its natural gas, and with several new export pipelines planned or already under construction, Russia hopes to increase this percentage in the next decade.

In order to offset its own declining production and maintain its export level, Gazprom, via natural gas trader Itera, contracted to buy 353 billion cubic feet (Bcf) of gas from Turkmenistan in 2002. As

Kazakhstan, Turkmenistan, and Uzbekistan continue to develop their natural gas industries and increase their production, senior Russian officials--including President Putin--have called for a Eurasian alliance to offset the impact of European natural gas market liberalization. According to Putin, the so-called "Gas OPEC," uniting Russia with the three big natural gas-producing countries in Central Asia, would "bring an element of stability into the transportation of natural gas on a long-term basis." Analysts have criticized the alliance proposal as a Russian attempt to exercise control over Central Asian natural gas exports.

Natural Gas Export Pipelines

In an effort to diversify its export routes and reach new markets, Russia is planning to build several new natural gas export pipelines. The Blue Stream pipeline to Turkey is the centerpiece of Russia's export diversification strategy. The pipeline, which will supply Turkey with 565 Bcf of natural gas via twin pipelines laid on the bottom of the Black Sea, is nearing completion, and should be operational by the fall of 2002. The December 2001 resolution of the dispute between Russia and Ukraine over Ukraine's unsanctioned removal of natural gas has caused Gazprom to drop plans to build a "Ukraine bypass" pipeline, but plans for the second branch of the Yamal-Europe pipeline--to Europe via Belarus--are in development. In addition, Russia is looking eastwards, with several potential natural gas pipelines to China currently under consideration.

COAL

With 173 billion short tons in proven coal reserves, Russia holds the world's second largest coal reserves, behind only the United States. However, years of poor management during the Soviet era, combined with a sharp decline in demand for coal during the early 1990s, significantly undermined the Russian coal sector's viability in the early 1990s. By 1993, Russian government subsidies to the coal sector became unsustainably high, exceeding 1% of the country's GDP, according to the World Bank. As production began to slump, Russia initiated a comprehensive restructuring of the coal sector in the mid-1990s.

As a result of the restructuring, the state coal company, RosUgol, has been phased out, production subsidies have ended, and mines with no economic future are being closed. With over $1.3 billion in financial assistance provided by the World Bank, the restructuring efforts are paying off, and the transition of Russia's coal sector from a massively-subsidized industry into a streamlined, profitable operation is almost complete. After years of decline, which saw Russian coal production decrease by 41%--from 406 million short tons (Mmst) in 1992 to 241 Mmst in 1998--in 1999, the reformed coal sector increased its production to 259 Mmst. EIA preliminary data for 2000 shows that Russia's coal production increased to 281 Mmst, and Russia's State Statistics Committee reports that the country's coal production rose again in 2001. Russia's Ministry of Energy has projected a 0.3% coal production increase in 2002.

Many of Russia's major coal basins are in West Siberia, and in 2001, the region's coal mines accounted for 48% of Russia's overall coal production. Kuzbassrazrezugol and Krasnoyarskugol, both located in West Siberia, were Russia's largest coal producers in 2001, with output of 36.3 Mmst and 35.3 Mmst, respectively. In addition, through the first seven months of 2001, Russia's State Statistics Committee reported that Russia's coal exports increased during the same time period by 30% year-on-year, including a 41.5% increase in exports to countries outside the CIS and Baltics.

With Russia's determination to increase its oil and natural gas exports, Russia's coal consumption is slated to rise. Although coal accounted for just 16% of Russia's domestic energy consumption in 1999, the government is committed to increase that percentage to as high as 28%. Russia consumed 298 Mmst of coal in 2000, but the country's energy strategy calls for coal production to climb to 335 Mmst in 2010, and then to 430 Mmst in 2020.

Nevertheless, the Russian Trade Union of Coal Miners complained in March 2002 of a lack of demand for Russian coal. Despite the sector's increased productivity, the Union's chairman, Ivan Mokhnachuk, said that coal deliveries to power-generation facilities fell by 4.4 Mmst in 2001, while coal stocks in depots increased by 33% over the previous year. At the same time, he noted, Russia imported 28.4 Mmst of coal

from Kazakhstan. The Russian Trade Union of Coal Miners has accused both Kazakhstan and China of dumping coal on the Russian market, reducing demand for Russian-produced coal.

ELECTRICITY

Russia's mammoth power sector, which includes over 440 thermal and hydropower plants, plus 29 nuclear reactors, has a total electric generation capacity of 203 gigawatts (GW). With 139 GW of production capacity, thermal power (oil-, gas-, and coal-fired plants) accounts for 68% of the country's power generation capacity, while hydropower plants account for an additional 44 GW (21.5% of total installed power capacity). Russia's electricity sector is dominated by Unified Energy Systems (UES), which is 52%-owned by the Russian government. UES, headed by former privatization minister Anatoly Chubais, controls approximately 70% of the country's distribution system and oversees Russia's 72 regional electricity companies, called *energos*.

Russia shut down several nuclear reactors during the 1990s, leading to a drop in the country's power-generating capacity during the last decade from 213 GW in 1992. Nonetheless, Russia still has sufficient power production potential to supply domestic consumers, as well as export power to other countries. In 1999, Russia's total electricity generation broke a decade-long downward trend by inching up from 788 billion kilowatt-hours (Bkwh) produced in 1998 to 801 Bkwh, followed by a jump to 836 Bkwh of electricity produced in 2000.

Similarly, the economic recovery after the August 1998 financial crisis resulted in an increase in the country's total electricity consumption, from 715 Bkwh in 1998 to 767 Bkwh in 2000. Increased industrial demand for electricity also has forced power stations to operate at higher capacity, straining power companies' ability to procure fuel supplies at a time when Gazprom is continuing to reduce natural gas supplies to UES. A lack of fuel supplies at power stations has already led to periodic power outages.

Electricity Sector Restructuring

Russia's aging power sector is in serious need of investment and reform. Much of the sector is obsolete by Western standards, and Russia lacks the money to pay for necessary maintenance. UES estimates that between $20 billion and $35 billion in investment will be needed over the next 10 years for maintenance and modernization efforts, but the company currently only has about $1 billion per year to invest. Analysts have estimated that if rates of investment stay at present levels, 32% of the current stock of electricity generating equipment will be out of commission by 2005, prompting a crisis in electricity production that may lead to widespread regional power shortages.

In an effort to entice foreign electricity companies to invest in Russia's power sector, numerous reform plans have been debated over the past decade, to no avail. However, the severe power outages in Russia's Far East during the winter of 2000-2001 made power sector restructuring a high priority, and in May 2001, the Russian government approved a blueprint for electricity sector restructuring. The restructuring plan will break the UES monopoly into separate generation and distribution units, then split up the generation assets further. Russian government officials hope this will pave the way for privatization of independent power-generating companies and thereby attract much needed investment to the sector.

Electricity Exports

UES has begun to focus on electricity exports in order to increase its cash flow to allow it to procure fuel supplies, as well as to invest in maintenance and modernization projects. In October 2000, UES began to supply electricity to Europe as part of an international project to create an "East-West energy bridge." UES is participating in the Baltrel program to create an energy ring with power companies in the Baltic states, and it has also signed contracts to export power to Turkey via Georgia. In addition, in August 2001 the Ukrainian and Russian electricity grids were re-connected, allowing Russia to export electricity via Ukraine to Moldova, as well as to access the Romanian, Bulgarian, and Balkan markets.

In March 2002, during a joint meeting of the CIS Electric Power Council and the Union of the Electric Industry (Eurelectric) in Warsaw, UES Chairman Anatoly Chubais appealed to European colleagues to

"destroy the iron curtain" between the energy systems of the East and the West. The first steps towards synchronization of energy systems have already been taken, as the Union for the Coordination of Transmission of Electricity (UCTE), of which 20 European countries are members, has entered into discussions with its eastern colleagues over the technological and operational aspects of amalgamating their systems.

Nuclear

With the opening of the 1,000-megawatt (MW) Rostov-1 reactor in March 2001, Russia now operates 30 nuclear reactors at 10 locations, all west of the Ural Mountains. The country has a total installed nuclear capacity of 22 GW, and in 1999 Russia's nuclear plants generated 111 Bkwh of power, accounting for 14% of the country's total electricity generation. However, Russia's nuclear power plants are aging, and the nuclear power industry has been hard hit by Russia's transition to a market economy. Russia already has shut down four reactors that were over 30 years old (the maximum prescribed service life for a reactor), but 15 of the country's 29 operating units are over 20 years old, and by 2005, seven of those reactors will have been in service for 30 years.

With Russia's plans to export additional natural gas to the West, the country's energy strategy is to increase its use of nuclear power over the next 20 years to meet domestic electricity needs. In order to do so, additional capacity will be needed, but the nuclear industry's lack of money has forced Minatom, the government agency responsible for overseeing the country's nuclear power plants, to focus on extending the service life of existing units instead of building new ones. Safety issues are an ongoing concern, especially with regard to the 16 relatively old reactors of the RBMK design used at Chernobyl. Older RBMK units at Kursk and St. Petersburg are scheduled to be overhauled and equipped with stopgap safety improvements to prolong their lives for another three decades.

Minatom is hoping to complete construction on five nuclear reactors that have been under construction since the 1980s, as well as to build 25 new reactors during the next 20 years. In February 2001, Russia's Deputy Minister of Atomic Energy, Bulat Nigmatulin, said the ministry would finance most of the $1.5 billion necessary to complete the construction of the five reactors by 2005. Although the Rostov-1 reactor is now operational, both the 1,000-MW Kalinin-3 reactor and the 1,000-MW Kursk-5 reactor are still under construction. In addition, Western nuclear experts have expressed serious doubts that Russia can finance the construction of 25 additional reactors on its own.

To increase its ability to finance domestic nuclear projects, in October 2000 Russia announced plans to market nuclear power plants to countries in Asia and Africa. The first of such plants, a $1.2-billion project for two 1,000-MW reactors, was sold to India, to be installed near Chennai by 2008. Russia also negotiated a similar deal with Iran to build the Bushehr nuclear power plant, and in November 2001, Russia delivered the first reactor body to Iran. According to the International Atomic Energy Agency, Russian-designed reactors would not be licensable in Western countries because they do not have all of the mandatory safety features, such as a containment dome.

ENVIRONMENT

After years of neglect under the Soviet Union, the environment has become a pertinent issue in today's Russia. Soviet policies that encouraged rapid industrialization and development left a legacy of air pollution and nuclear waste with which Russia now is struggling to contend. Although environmental awareness in Russia is rising, the cost of remediating the country's environmental hot spots is high, and the newly created Ministry of Natural Resources has a limited budget. As a result, cleanup has been slow, and environmental protection has not been a top priority for the Russian government.

The economic contraction in the aftermath of the Soviet Union's collapse caused a drop in industrial production, resulting in less energy consumption and a drop in Russia's carbon emissions. However, energy and carbon intensities in Russia remain high, and although per capita carbon emissions have fallen over the past 12 years, Russia will need to pursue more sustainable environmental policies in order to maintain this trend, especially with the rebound in industrial production since the August 1998 financial crisis. Russia

has abundant fossil fuel resources, but the country will need to pursue more renewable energy options and cleaner environmental technologies in order to preserve its natural wonders and protect its environment for future generations.

COUNTRY OVERVIEW
President: Vladimir Vladimirovich Putin (acting president since December 31, 1999; president since May 7, 2000)
Prime Minister: Mikhail Mikhaylovich Kasyanov (since May 7, 2000)
Independence: August 24, 1991 (from Soviet Union). National holiday: Independence Day, June 12, 1990
Population (7/01E): 145.5 million
Location: Eurasia
Size: 6,592,850 sq. mi., slightly more than 1.8 times the size of the United States
Major Cities: Moscow, St. Petersburg, Yekaterinburg, Irkutsk, Murmansk, Yakutsk, Vladivostok
Languages: Russian, others
Ethnic Groups: Russian 81.5%, Tatar 3.8%, Ukrainian 3%, Chuvash 1.2%, Bashkir 0.9%, Belorussian 0.8%, Moldovan 0.7%, other 8.1%
Religions: Russian Orthodox, Muslim, other

ECONOMIC OVERVIEW
Minister of Economic Development and Trade: German Oskarovich Gref
Minister of Finance: Aleksey Leonidovich Kudrin
Currency: Ruble
Market Exchange Rate (4/25/02): $1 = 31.19 rubles
Nominal Gross Domestic Product (GDP) (2001E): $301.5 billion; **(2002E):** $327 billion
Real GDP Growth Rate (2001E): 5.1%; **(2002E):** 3.2%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 18.5%; **(2002E):** 12.8%
Official Unemployment Rate (2001E): 8.8%; **(2002E):** 8.6%
Current Account Balance (2001E): $34.3 billion; **(2002E):** $27.1 billion
Major Trading Partners (1999): Germany, Ukraine, U.S., Belarus, Italy, Netherlands, Kazakhstan
Merchandise Exports (2001E): $102.7 billion; **(2002E):** $103.7 billion
Merchandise Imports (2001E): $53.1 billion; **(2002E):** $60.0 billion
Merchandise Trade Balance (2001E): $49.6 billion; **(2002E):** $43.7 billion
Major Exports: Petroleum and petroleum products, natural gas, wood and wood products, metals, chemicals, and a wide variety of civilian and military manufactures
Major Imports: Machinery and equipment, consumer goods, medicines, meat, grain, sugar, semifinished metal products
External Debt (2001E): $154 billion

ENERGY OVERVIEW
Deputy Prime Minister (for Energy Issues): Viktor Borisovich Khristenko
Minister of Energy: Igor Khanukovich Yusufov
Minster of Atomic Energy: Aleksandr Yuryevich Rumyantsev
Proven Oil Reserves (1/1/02E): 48.6 billion barrels
Oil Production (2001E): 7.29 million bb/d (of which 7.05 million bbl/d was crude); **(2002E):** 7.43 million bbl/d
Oil Consumption (2001E): 2.38 million bbl/d; **(2002E):** 2.42 million bbl/d
Net Oil Exports (2001E): 4.91 million bbl/d; (**2002E):** 5.01 million bbl/d
Major Oil Customers: Europe, Commonwealth of Independent States
Crude Refining Capacity (1/1/02E): 6.6 million bbl/d
Proven Natural Gas Reserves (1/1/02E): 1,700 trillion cubic feet (Tcf)
Natural Gas Production (2001E): 20.5 Tcf
Natural Gas Consumption (2001E): 13.8 Tcf
Net Natural Gas Exports (2001E): 6.7 Tcf
Coal Reserves (1/1/01E): 173 billion short tons
Coal Production (2000E): 281 million short tons (Mmst)

Coal Consumption (2000E): 298 Mmst
Electric Installed Capacity (2000E): 203 gigawatts (68% thermal, 21.5% hydro, 10.5% nuclear)
Electricity Generation (2000E): 836 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 767 Bkwh
Net Electricity Exports (2000E): 69 Bkwh

ENVIRONMENTAL OVERVIEW
Minister of Natural Resources: Vitaliy Grigoryevich Artyukhov
Total Energy Consumption (1999E): 26.0 quadrillion Btu* (6.8%) of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 400.1 million metric tons of carbon (6.5% of world carbon emissions)
Per Capita Energy Consumption (1999E): 176.7 million Btu (vs. U.S. value of 355.9 million Btu)
Per Capita Carbon Emissions (1999E): 2.7 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (1999E): 72,133 Btu/$1990 (vs U.S. value of 12,638 Btu/$1990)**
Carbon Intensity (1999E): 1.1 metric tons of carbon/thousand $1990 (vs U.S. value of 0.20 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1997E): Industrial (64.3%), Residential (17.9%), Transportation (17.1%), Commercial (0.7%)
Sectoral Share of Carbon Emissions (1997E): Industrial (64.8%), Transportation (17.8%), Residential (17.4%)
Fuel Share of Energy Consumption (1999E): Natural Gas (54.3%), Oil (19.3%), Coal (16.0%)
Fuel Share of Carbon Emissions (1998E): Natural Gas (50.8%), Coal (26.2%), Oil (22.9%)
Renewable Energy Consumption (1997E): 2,482 trillion Btu* (1% increase from 1996)
Number of People per Motor Vehicle (1997): 6.5 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 28th, 1994). Under the negotiated Kyoto Protocol (signed on March 11th, 1999, but not yet ratified), Russia has agreed to stabilize greenhouse gases at 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: air pollution from heavy industry, emissions of coal-fired electric plants, and transportation in major cities; industrial, municipal, and agricultural pollution of inland waterways and sea coasts; deforestation; soil erosion; soil contamination from improper application of agricultural chemicals; scattered areas of sometimes intense radioactive contamination; ground water contamination from toxic waste.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Wetlands and Whaling. **Has signed, but not ratified:** Climate Change, Air Pollution-Sulphur 94.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999

ENERGY INDUSTRY
Organization: Russia's energy sector is overseen by the Ministry of Energy, except for nuclear power, which is administered by the Ministry of Atomic Energy (Minatom).

Russia's Oil Sector is dominated by large joint-stock companies, although smaller independent producers also produce oil. The major vertically integrated companies include Lukoil, Yukos, Surgutneftegaz, Tyumen Oil (TNK), Tatneft, Sibneft, Slavneft, and Rosneft. Transneft has a monopoly over crude oil

transport, while Transnefteprodukt transports petroleum products.

Russia's Natural Gas Sector is dominated by the joint-stock company Gazprom, which is 38% owned by the Russian government. Gazprom produces over 90% of the country's natural gas and also controls Russia's pipeline network. Itera has gained a foothold in the natural gas sector as Russia's second-largest natural gas exporter.

Russia's Coal Sector, formerly operated by RosUgol, a government-owned holding company that was organized along regional lines, has been restructured, with many unprofitable mines closed down, RosUgol eliminated, and the remaining efficient mines privatized. Kuzbassrazrezugol and Krasnoyarskugol were Russia's biggest coal producers in 2001.

Russia's Electricity Sector is operated by the joint-stock company Unified Energy Systems (UES), which is majority state-owned. UES controls approximately 70% of the country's distribution system, 21 thermal power plants, 8 nuclear power plants, and oversees the country's 72 regional electricity companies, known as *energos*.

Major Producing Oil Fields: Samotlor, Romashkino, Mamontov, Fedorov, Lyantor, Arlan, Krasnolenin, Vatyegan, Sutormin

Major Oil Terminals: Novorossiisk (Black Sea), Tuapse (Black Sea), Primorsk (Baltic Sea); Russia also uses ports at Ventspils (Latvia), Odesa (Ukraine), Klaipeda (Lithuania), and Butinge (Lithuania)

Major Oil Export Pipelines outside the Commonwealth of Independent States: Friendship (Druzhba) (1.2 million bbl/d nominal capacity)

Major Oil Refineries (1/1/02E) (Capacity in bbl/d): Omsk (566,000), Angarsk (441,000), Nizhniy Novgorod (438,000), Grozny (390,000), Kirishi (388,000), Novo-Ufa (380,000), Ryazan (361,000), Novo-Kuibishev (309,000), Yaroslavl (290,000), Perm (279,000), Ufaneftekhim (251,000), Salavatnefteorgsintez (247,000), Moscow (243,000), Ufa (235,000), Syzran (211,000), Volgograd (200,000), Saratov (177,000), Orsk (159,000), Samara-Kuibishev (154,000), Achinsk (147,000), Ukhta (127,000), Nizhnekamsk (120,000), Komsomolsk (108,000)

Major Foreign Oil Company Involvement: Agip, BP, British Gas, ChevronTexaco, Statoil, Conoco, ExxonMobil, Neste Oy, Norsk Hydro, McDermott, Mitsubishi, Mitsui, Royal Dutch/Shell, and TotalFina Elf.

Major Producing Natural Gas Fields: Urengoy, Yamburg, Medvezh, Orenburg, Severo Urengoy, Vyngapurov

Major Natural Gas Export Pipelines outside the Commonwealth of Independent States (Capacity): Brotherhood (*Bratrstvo*), Progress, and Union (*Soyuz*) (to Europe, via Ukraine) (1 Tcf each); Northern Lights (0.8 Tcf) (to Europe, via Belarus and Ukraine), Volga/Urals-Vyborg (to Finland) (0.1 Tcf); Yamal (to Europe, via Belarus) (1.0 Tcf); Blue Stream (0.56 Tcf) (to Turkey, under construction)

Major Coal Producing Basins: Chelyabinsk, Kansk-Achinsk, Kuznetsk, Lena, Moscow, Pechora, Raychikhinsk, South Yakutia, Taymyr, Zyryanka

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Sources for this report include: Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring International Reports, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, Current Digest of the Post-Soviet Press, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, Energy Day, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Gas Connections, Hart's European Fuel News, Interfax News Agency, The International Herald

Tribune, International Petroleum Finance, ITAR-TASS News Agency, Mining & Metals Report, The Moscow Times, Oil and Gas Journal, Petroleum Economist, Petroleum Report, Platt's International Coal Report, Platt's Oilgram News, Polish News Bulletin, PR Newswire, Project Finance, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, Warsaw Business Journal, World Gas Intelligence, and World Markets Online.

Links

For more information from EIA on Russia, please see:
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Links to other U.S. government sites:
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Energy Information Administration

July 2002

Caspian Sea Region: Regional Conflicts

Development of Caspian Sea oil and natural gas, along with the necessary export pipelines, has been slowed by regional conflicts, political instability, and a lack of regional cooperation. Many of the proposed export routes pass through areas where conflicts remain unresolved. Although new oil and natural gas export pipelines offer the hope of longer-term prosperity, the region's numerous flashpoints and ongoing instability have caused energy companies and potential investors to think twice before investing in the construction of proposed pipelines.

Most of these conflicts are in the Trans-Caucasus part of the Caspian region, where conflicts in Nagorno-Karabakh, Georgia, and the Chechen republic of southern Russia have hindered the development of export routes westward from the Caspian Sea. On the east side of the Caspian, the unstable situation in Afghanistan, following over 23 years of war, has stifled the development of export routes to the southeast, and the continued threat of Islamic fundamentalism in Central Asia, especially in Uzbekistan, may prohibit any new export pipelines involving that country. The threat of war between Pakistan and India serves as a further deterrent to Caspian export pipelines running southeast, either via Iran or Afghanistan.

In addition, the continuing unresolved legal status of the Caspian Sea has threatened to ignite conflict among several of the littoral states. Although Russia, Kazakhstan, and Azerbaijan have signed bilateral agreements demarcating their respective sectors of the Sea, no multilateral agreement has been concluded among the five littoral states, and the southern part of the Caspian, especially, has remained in dispute. Azerbaijan and Turkmenistan repeatedly have exchanged sharp words with regard to oil field claims in the Sea, and Iran's military response to an Azeri exploration vessel in July 2001 heightened tensions about oil and natural gas production in the southern Caspian. Several trans-Caspian oil and natural gas export pipelines have been proposed, but none will be implemented until an agreement clarifying the Sea's status can be reached among the five littoral states.

Armenia-Azerbaijan: Nagorno-Karabakh's Unresolved Status

The western route for "early oil" from Baku, Azerbaijan, to Supsa on the Georgian Black Sea Coast (as well as the planned "Main Export Route" from Baku to Ceyhan on the Turkish Mediterranean Coast) passes just north of the breakaway Azeri region of Nagorno-Karabakh. Nagorno-Karabakh is a

mountainous territory populated mainly by ethnic Armenians but nestled inside predominantly Muslim Azerbaijan. Its declaration of independence in 1988 sparked a six-year war that killed more than 30,000 people and drove about 1 million people, mostly Azeris, from their homes. Six years of fighting ended in a Russian-mediated cease-fire that left the enclave and some surrounding territory--about one-fifth of the territory of Azerbaijan--firmly under control of an unrecognized ethnic Armenian government and its militia.

Since the May 1994 ceasefire, hundreds of people have been killed each year in sporadic violence and by mines that mark a no-man's-land around the 1,600-square mile mountainous region. Azerbajian has maintained an economic blockade of Armenia since the conflict broke out, and relationships between Russia and Azerbaijan were strained when it became known that Russia had shipped over $1 billion of arms to Armenia from 1993 to 1995. Armenia and Russia signed an updated friendship treaty, as well as a deal to create a joint venture with Russia's Gazprom to supply Armenia with natural gas, since Armenia's fuel supplies have been constrained by the Azeri blockade.

Following the imposition of that blockade, the United States passed section 907 of the Freedom Support Act in October 1992, which restricts U.S. government assistance to Azerbaijan until it has taken "demonstrable steps to cease all blockades and other offensive uses of force against Armenia and Nagorno-Karabakh." In October 1998, U.S. legislation was approved that permitted some exemptions (including the U.S. Export-Import Bank, the Overseas Private Investment Corporation (OPIC), and the Trade and Development Agency) from the bans contained in section 907. On January 25, 2002, U.S. President George W. Bush waived Section 907 in recognition of Azerbaijan's support for the war on terrorism. However, the unresolved status of Nagorno-Karabakh has impeded economic development in both former Soviet republics.

In 1994, the Organization for Security and Cooperation in Europe (OSCE) formed the "Minsk Group"--made up of Russia, the United States, and France--in an effort to bring the sides closer together to forge a lasting peace. Since 1999, Azeri President Heydar Aliyev and Armenian President Robert Kocharian have met over 15 times, including an April 2001 meeting in Key West, Florida, that both sides agreed was very productive.

The contours of a possible deal are becoming clear: the Armenians would give Azerbaijan back six of the seven regions they captured, while Nagorno-Karabakh and the adjacent Lachin region that links it to Armenia would be granted self-governing status. Azerbaijan would be compensated with an internationally protected road linking it to its isolated exclave of Nakhchivan. However, with a possible peace settlement in the works, negotiations have reached a perilous stage, and several meetings have been postponed as both presidents seek to prepare their populations for a final deal.

Georgia: Abkhazia, Ossetia Separatism

The western route for early oil from Azerbaijan goes from Baku to the Georgian port of Supsa on the Black Sea, and several other proposed pipeline routes, including the proposed Baku-Ceyhan route to the Turkish Mediterranean coast, also pass through Georgia. Both pipeline routes pass near several regions

of Georgia that have been the site of separatist struggles in Abkhazia (northwest Georgia) and Ossetia (north central Georgia). Abkhazia fought a civil war with Georgia in 1992-1993, and has demanded to be a sovereign republic with minimal ties to Georgia. Georgia has expressed a willingness to grant Abkhazia some autonomy. The port of Supsa is just 12 miles from a buffer zone between Abkhazia and Georgia.

Negotiations have included proposals to route future oil pipelines across the rebel region, on the premise that economic cooperation could help bring peace to the region. Nevertheless, pipeline construction on the western route was suspended briefly in October 1998 because of fighting between government forces and those led by Akaki Eliava, a supporter of the late Georgian President Gamsakhurdia. In addition, Georgian President Shevardnaze escaped assassination attempts in 1995 and 1998 that were reported to have been linked to disputes over construction of oil pipelines through Georgian territory.

A coup attempt in 1998 led the chairman of the National Independence Party to call for the North Atlantic Treaty Organization (NATO) or the United States to station a military contingent in Georgia to protect Caspian oil transport. In December 1998, representatives from the GUUAM Group (Georgia, Ukraine, Uzbekistan, Azerbaijan, Moldova) held talks about setting up a special peacekeeping force to protect the oil export pipelines. Proposals were made to work with NATO to set up this force within the framework of the Partnership for Peace Program, which was established by NATO to strengthen ties with former Eastern Bloc and former Soviet states. While fighting has subsided and negotiations have continued to ease the standoff, a lasting resolution has not been agreed upon yet.

As part of the U.S.-led war on terrorism, U.S. military advisors have been working with the Georgian military to counter threats emanating from the Pankisi Gorge. Also, in early May 2002, thieves in Georgia illegally tapped the Baku-Supsa pipeline, causing a small leak. After security was upgraded and the damage was repaired, exports via the pipeline resumed following a three-day suspension.

Russia: Chechnya Conflict

The original northern route for early oil from Azerbaijan, the Baku-Novorossiisk pipeline, passed for 80 miles through the Russian Republic of Chechnya. Russian troops entered Chechnya in December 1994, and after almost two years of fighting, a peace agreement was reached. The peace agreement cleared the way for the July 1997 tripartite agreement between Azerbaijan, Chechnya, and Russia on early oil exports from Azerbaijan.

Although the deal allowed necessary repairs to begin on the existing oil pipeline, it did not settle the issues of regional security and pipeline tariffs. Russia's Transneft pipeline transport company and Chechen government officials have clashed in the past over the issue of tariffs and war reparations from Russia. The renewal of war in Chechnya in 1999 prompted Transneft to construct a 300,000-bbl/d Chechnya bypass, which was completed in 2000, but the devastation wrought by the two wars, as well as the lack of a peace agreement, may make the pipeline a target for terrorist attacks.

Afghanistan: War-Scarred and Unstable

In the mid-1990s, a Memorandum of Understanding was signed between Turkmenistan, Afghanistan,

Pakistan, and Uzbekistan to build the Central Asia natural gas pipeline (Centgas) stretching from Turkmenistan to Pakistan (and perhaps India) via Afghanistan. In addition, the proposed Central Asia Oil Pipeline also would pass from Turkmenistan through Afghanistan en route to a Pakistani port on the Arabian Sea.

However, ongoing fighting between the Taliban and the Northern Alliance in Afghanistan during the late 1990s prevented the projects from going forward. Following the August 20, 1998, U.S. bombing raids on Afghan strongholds of suspected terrorist Osama bin Laden, Unocal announced that it was suspending work on the gas pipeline, and in December 1998, it withdrew from the Centgas consortium, citing the turmoil and high risk in the region. In April 1999, Pakistan, Turkmenistan and Afghanistan agreed to reactivate the Centgas project, and to ask the Centgas consortium, now led by Saudi Arabia's Delta Oil, to proceed, but continuing fighting, as well as sanctions imposed by the United States and the United Nations, kept the project on hold.

Since the Taliban government's ouster in December 2001, Afghanistan's new government has received international recognition and assistance. Although an international police force is operating in the capital of Kabul, sporadic violence is still occurring throughout the country. In addition, after 23 years of warfare, Afghanistan's infrastructure is severely devastated, and the country needs help to rebuild its economy and infrastructure in order to attract foreign investment to build a pipeline across its territory.

Uzbekistan: Islamic Fundamentalism

A proposed natural gas pipeline going eastward from the Caspian Sea region to China would be routed through Uzbekistan. Since six still-unexplained car bombs exploded in Tashkent in 1999, Uzbek government officials have been worried about terrorist incursions into Uzbek territory by Islamic fundamentalists. The Islamic Movement of Uzbekistan (IMU), led by Juma Namangani, has been the principle cause for concern, especially in the populous Fergana Valley.

As a result, the Uzbek government has been taking extra steps to curb the rise of Islamic fundamentalism, such as increasing security measures by tightening border regulations with Afghanistan, Tajikistan, and Kyrgyzstan. Uzbekistan is receiving support from the United States in anti-terrorist countermeasures after Uzbekistan lent its airspace and military bases for the campaign against the Taliban in Afghanistan in late 2001. According to Uzbek officials, Namangani and a number of his followers were killed by U.S.-led bombing of Afghanistan in 2001, and the IMU threat has receded substantially.

Pakistan-India: Increased Tensions

The proposed natural gas and oil pipelines from the Caspian region through Afghanistan would terminate in either Pakistan or India, serving markets in those populous countries. However, following an attack on India's parliament in December 2001 by Kashmiri separatists, tensions between India and Pakistan surged, leading to fears of a fourth war between the two countries in the last 60 years. Pakistan, which India claimed was accountable for the attacks, has announced its intention to crack down on Islamic fundamentalists in its country.

Southern Caspian Sea: Harsh Words and Provocative Actions

Several trans-Caspian pipelines have been proposed, including the Trans-Caspian Gas Pipeline that would run under the Sea from Turkmenistan to Azerbaijan. Both Russia and Iran have opposed this pipeline on environmental grounds, and it is clear that no subsea pipeline will be built until a multilateral agreement on the legal status of the Sea is reached by the littoral states. In addition, the lack of an agreement on the legal status of the Sea may not only serve as a deterrent to the exploitation of the Sea's resources and to the construction of export pipelines, but it also may prove to be the catalyst for conflict in the region.

While Azerbaijan and Turkmenistan have traded harsh rhetoric over the demarcation of their sectors of the Sea, in the summer of 2001, Iran raised the stakes in the struggle over ownership rights of disputed Caspian waters. On July 23, 2001, after an Iranian fighter jet flew over an Azeri exploration vessel in the southern Caspian Sea, an Iranian warship followed by ordering the exploration vessel to retreat five miles north. Iran claimed that the boat, which had British Petroleum (BP) specialists on board, was exploring waters that Iran claims as its own. For its part, Azerbaijan argued that it had licensed the Araz-Alov-Sharg field three years earlier without complaint from Iran. BP has suspended work at the field pending a resolution of the dispute.

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Caspian Sea Region

The Caspian Sea region, including the Sea and the littoral states surrounding it, is important to world energy markets because it holds large reserves of undeveloped oil and natural gas. The Caspian Sea's mineral wealth has resulted in disagreements between the five countries over ownership of the resources, and the region's huge energy potential has sparked fierce competition--between producers as well as consumers--over the final export routes for this oil and natural gas.

Note: Information contained in this report is the best available as of July 2002 and is subject to change.

GENERAL BACKGROUND

The Caspian Sea is located in northwest Asia, landlocked between Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan. Since the breakup of the Soviet Union in 1991, the Caspian Sea--as well as the region surrounding it--has became the focus of much international attention due to its huge oil and natural gas reserves. The Sea, which is 700 miles long, contains six separate identified hydrocarbon basins, although most of its oil and natural gas reserves have not been developed yet. Although the littoral states of the Caspian Sea already are major energy producers, many areas of the Sea and the surrounding area remain unexplored.

The prospect of potentially enormous hydrocarbon reserves is part of the allure of the Caspian Sea region (which is defined here to include Azerbaijan, Kazakhstan, Turkmenistan, and the regions of Iran and Russia that are near the Caspian Sea). The Caspian region contains 10 billion barrels of proven oil reserves (defined as oil and natural gas liquids deposits that are considered 90% probable). In addition, despite a string of disappointing recent drilling results, mostly in Azerbaijan, the region's possible oil reserves (defined as 50% probable) could yield another 233 billion barrels of oil.

Overall, proven natural gas reserves in the Caspian region are estimated at around 170 Tcf. Possible natural gas reserves in the Caspian region are even larger, and could yield another 293 trillion cubic feet (Tcf) of natural gas. Turkmenistan (101 Tcf) and Kazakhstan (65 Tcf) are among the top 20 countries in the world in terms of proven natural gas reserves. Although it is not technically part of the Caspian Sea region, nearby Uzbekistan (66.2 Tcf in proven natural gas reserves) also holds significant natural gas deposits.

Since they became independent in 1991, Azerbaijan, Kazakhstan, and Turkmenistan have sought to develop their national oil and natural gas industries. Although the Soviet Union attempted to exploit each of the republic's energy resources, a lack of investment, deteriorating infrastructure, and out-dated technology resulted in declining rates of production in each of the countries at the time of the Soviet Union's collapse in 1991. Over the last 11 years, however, Azerbaijan and Kazakhstan, in particular, have received large amounts of foreign investment in their oil and natural gas sectors. With additional investment, the application of Western technology, and the development of new export outlets, oil and natural gas production in the Caspian region could grow rapidly.

Caspian Legal Status Unresolved

In order for the Caspian Sea region to realize its full energy potential, however, the littoral states must first agree on the legal status of the Sea. Prior to 1991, only two countries--the Soviet Union and Iran--bordered the Caspian Sea, and the legal status of the Sea was governed by 1921 and 1940 bilateral treaties. With the collapse of the Soviet Union and the emergence of Kazakhstan, Turkmenistan, and Azerbaijan as independent states, ownership and development rights in the Sea have been called into question.

Most of Azerbaijan's oil resources (proven as well as possible reserves) are located offshore, and perhaps 30% to 40% of the total oil resources of Kazakhstan and Turkmenistan are offshore as well. Currently, there is no agreed-upon convention that delineates the littoral states' ownership of the Sea's resources or their development rights. The potential oil and natural gas wealth, along with the corresponding environmental risks of resource development in the Caspian, have heightened the stakes for each country.

As a result, several conflicts have arisen over mutual claims to different regions of the Sea, especially in its southern waters. In July 2001, Iranian military gunboats confronted a British Petroleum (BP) Azeri research vessel exploring the Araz-Alov-Sharg structure, ordering the ship out of waters Iran

claims as its own. Azerbaijan, for its part, has objected to Iran's decision to award Royal Dutch/Shell and Lasmo a license to conduct seismic surveys in a region that Azerbaijan considers to fall in its territory. In addition, Turkmenistan and Azerbaijan remain locked in a dispute over the Serdar/Kyapaz field, while Turkmenistan claims that portions of Azerbaijan's Azeri and Chirag fields--which Turkmen officials call Khazar and Osman, respectively--lie within its territorial waters.

Thus, the unresolved status of the Caspian Sea has hindered further development of the Sea's oil and natural gas resources, as well as the construction of potential export pipelines from the region. Negotiations between the littoral states have made slow progress in ironing out differences between the countries: while Russia, Azerbaijan, and Kazakhstan have agreed on dividing the Sea by a "modified median" principle, Iran insists on an equal division of the Sea, and Turkmenistan agrees on the principle of dividing the Sea, but not the method. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status, prompting several states to sign bilateral agreements in an effort to solve the problem.

OIL

Despite the lack of a multilateral agreement on the Sea, several countries are undertaking active exploration and development programs in what is generally considered to be their sector of the Caspian Sea. In particular, Azerbaijan and Kazakhstan have made substantial progress in developing their offshore oil reserves.

Azerbaijan has signed a number of production-sharing agreements--both onshore and offshore--in order to develop its oil and natural gas industries. A significant percentage of Azerbaijan's oil production comes from the shallow-water section of the Gunashli field, located 60 miles off the Azeri coast. Although the country's oil production fell after 1991 to just 180,000 barrels per day (bbl/d) in 1997, Azerbaijan's oil production rebounded to 311,200 bbl/d in 2001 with the help of international investment in its oil sector.

Kazakhstan also has opened its resources to development by foreign companies. International oil projects in Kazakhstan have taken the form of joint ventures, production-sharing agreements, and exploration/field concessions. After Russia, Kazakhstan was the largest oil-producing republic in the Soviet Union, but after independence, Kazakhstan's oil production dropped more than 115,000 bbl/d, to 414,000 bbl/d, in 1995. Boosted by foreign investment in its oil sector, Kazakhstan's oil production has increased steadily since then, with output of 811,000 bbl/d in 2001, most of which came from three large onshore fields (Tengiz, Uzen, and Karachaganak). In addition, preliminary drilling in Kazakhstan's offshore sector of the Caspian has revealed bountiful oil deposits, especially in the Kashagan field, raising hopes that Kazakhstan may become one of the world's largest oil producers.

Overall, oil production in the Caspian Sea region reached approximately 1.3 million bbl/d in 2001. Production in the region is projected to increase severalfold, led by three major projects currently under development in Azerbaijan and Kazakhstan:

- In April 1993, Chevron concluded a historic $20 billion deal with Kazakhstan to create the Tengizchevroil joint venture to develop the Tengiz oil field, estimated to contain recoverable oil reserves of six to nine billion barrels. Tengizchevroil was producing approximately 250,000 bbl/d in June 2002, and the consortium is planning to invest $3 billion over the next three years to boost production capacity at the field now that Caspian Pipeline Consortium's Tengiz-Novorosiisk export pipeline is operational. Given adequate export outlets, the Tengizchevroil joint venture could reach peak production of 750,000 bbl/d by 2010.

- In what was described as "the deal of the century," in September 1994 the Azerbaijan International Operating Company (AIOC) signed an $8 billion, 30-year contract to develop three Caspian Sea fields--Azeri, Chirag, and the deepwater portions of Gunashli--with proven reserves

estimated at three to five billion barrels. Almost all of Azerbaijan's production increases since 1997 have come from AIOC, which produced an average of 120,000 bbl/d of oil in the first four months of 2002. In August 2001, AIOC and Azeri government officials signed an agreement to carry out an expansion, with oil production at ACG expected to reach 800,000 bbl/d by the end of the decade. The planned Baku-Ceyhan Main Export Pipeline will be the main vehicle for ACG oil exports.

- Although signed with less fanfare in 1997, the offshore Kashagan block being developed by the Agip Kazakhstan North Caspian Operating Company (Agip KCO, formerly OKIOC) may turn out to be more lucrative than both the Tengiz and the ACG group of deposits combined. Exploration and preliminary drilling in the Kashagan block has produced spectacular results, with analysts hailing the field as the largest oil discovery in the last 30 years. Although Agip KCO released estimates in June 2002 that the Kashagan field holds between seven and nine billion barrels of crude in proven reserves, as well as 38 billion barrels in probable reserves, both Kazakh officials and energy analysts have called that estimate "conservative."

These projects, along with others currently underway, could help boost Caspian Sea region production to around 3.7 million bbl/d by 2010. EIA expects production capacity from the Caspian basin to exceed 6.5 million barrels per day by 2020. Although not "another Middle East," as some analysts believed in the early 1990s, the Caspian Sea region is comparable to the North Sea in its hydrocarbon potential.

NATURAL GAS

Unlike with oil, the Caspian region's natural gas resources were extensively developed during the Soviet era. Caspian Sea region natural gas production, not including major Central Asian natural gas producer Uzbekistan, was 3.9 Tcf in 1990, but the collapse of the Soviet Union led to downturns across the region. After 1991, Caspian region natural gas, mostly from Turkmenistan,

became a competitor with Gazprom, the Russian state natural gas company. Since Gazprom owned all the pipelines, and since export routes for Caspian natural gas--such as the Central Asia-Center pipeline--were routed through Russia, Caspian natural gas was squeezed out of the hard currency market.

As a result, Turkmenistan's incentives for increasing its production of natural gas disappeared. The country's output dropped throughout the 1990s, plummeting from 2.02 Tcf in 1992 to just 466 billion cubic feet (Bcf) in 1998, when the country was locked in a pricing dispute with Russia over the export of Turkmen natural gas. With high world natural gas prices and a Turkmen-Russian agreement on Turkmen exports in place, the country's natural gas production rebounded to 788 Bcf in 1999, then skyrocketed to 1.64 Tcf in 2000. Turkmenistan has plans to boost natural gas output substantially over the next decade, contingent on securing adequate export routes, such as the proposed Trans-Caspian Gas Pipeline.

Uzbekistan is the third largest natural gas producer in the Commonwealth of Independent States and one of the top ten natural gas-producing countries in the world. Since becoming independent, Uzbekistan has ramped up its natural gas production nearly 32%, from 1.51 Tcf in 1992 to 1.99 Tcf in 2000. In order to offset declining production at some older fields such as Uchkir and Yangikazen, Uzbekistan is speeding up development at existing fields such as the Kandym and Garbi fields, as well as planning to explore for new reserves. However, since Uzbekistan is landlocked and its natural gas competes with Russian and Turkmen natural gas, Uzbekistan is limited in its ability to export. Instead, Uzbekistan has concentrated on supplying the Central Asian natural gas market, mainly through the Tashkent-Bishkek-Almaty pipeline.

With the emphasis on Azerbaijan's oil potential, the country's natural gas sector often has been overlooked. In the past, Azerbaijan has imported natural gas from Russia, Turkmenistan, and Iran to meet domestic needs, but consumption has been on the wane since the collapse of the Soviet Union, and in 2000, Azerbaijan's natural gas consumption and production were roughly equivalent at 200 Bcf. Azerbaijan is continuing to import natural gas, but the 1999 discovery of the Shah Deniz field will soon change that.

The Shah Deniz field, which is thought to be the world's largest natural gas discovery since 1978, is estimated to contain between 25 Tcf and 39 Tcf of possible (not proven) natural gas. Development of the field, which will cost upwards of $2.5 billion including related infrastructure, should produce the first natural gas by 2004, making Azerbaijan a significant net natural gas exporter. Already, Azerbaijan has secured an agreement with Turkey to export Azeri natural gas via a planned Baku-Erzurum pipeline.

As investment continues to pour into the Kazakh natural gas sector, the country's natural gas production is set to increase dramatically. In August 2001, the Kazakh Ministry for Energy and Mineral Resources approved a 15-year strategy for developing the country's natural gas sector that would increase natural gas production fivefold. According to the strategy, which the Kazakh government approved, Kazakhstan is aiming to increase its natural gas production to 1.2 Tcf by 2005, to 1.66 Tcf by 2010, and to 1.84 Tcf by

2015. Key to this strategy is the development of natural gas reserves at Kashagan, Karachaganak, and Tengiz. Provided that the necessary infrastructure is built, Kazakhstan soon could become a major natural gas exporter as well.

Overall, natural gas production in the Caspian Sea region reached nearly 2.1 Tcf in 2000. Projects currently underway could help boost Caspian Sea region natural gas production to over 6 Tcf by 2010, and the enactment of laws barring the flaring of associated natural gas may increase the region's total production. In 1999, Azerbaijan enacted a law requiring that each oil production project in the country include a plan to develop its natural gas potential, while Kazakhstan is requiring Agip KCO to capture and use all the associated natural gas from the Kashagan block. Previously, natural gas had been flared off in both countries instead of being piped to consumers because of a lack of a developed infrastructure to deliver natural gas from offshore fields.

EXPORT ISSUES

As increasing exploration and development in the Caspian Sea region leads to increased production, the countries of the region will have additional oil and natural gas supplies available for export. Already, in 2001, Kazakhstan's net oil exports were 631,000 bbl/d, while Azerbaijan's were 175,200 bbl/d. Overall, Caspian Sea region oil exports in 2001 amounted to about 920,000 bbl/d (of the 1.3 million bbl/d produced). With numerous oil projects in the region slated to boost production in the coming years, the region's net exports could increase to over 3 million bbl/d in 2010, and possibly another 2 million bbl/d on top of that by 2020.

With regards to natural gas, Turkmenistan led the way among Caspian Sea region producers with net exports of 1.38 Tcf in 2000. Overall, Caspian Sea region natural gas exports totaled just 1.2 Tcf in 2000, since both Azerbaijan and Kazakhstan have yet to tap their full natural gas production potential (and Kazakhstan is currently a net natural gas importer). With Azerbaijan's Shah

Deniz field in development, along with increased investment to develop infrastructure and markets for the region's natural gas, Caspian natural gas exports could increase by another 2-3 Tcf by 2020.

Existing Export Options

In order to boost oil and natural gas exports from the Caspian Sea region, a number of issues will need to be addressed. During the Soviet era, all of the oil and natural gas pipelines in the Caspian Sea region (aside from those in northern Iran) were designed to link the Soviet Union internally and were routed through Russia.

Prior to 1997, exporters of Caspian region oil had only one major pipeline option available to them, the 240,000-bbl/d Atyrau-Samara pipeline from Kazakhstan to Russia. Smaller amounts of oil were exported by barge and by rail through Russia, as well as by a second, smaller pipeline from Kazakhstan to Russia. In the decade since the collapse of the Soviet Union, several new oil export pipelines, such as the Baku-Novorossiisk, the Tengiz-Novorossiisk, and the Baku-Supsa pipelines, have been constructed, and the Atyrau-Samara pipeline recently was upgraded to increase its capacity to 300,000 bbl/d.

Nevertheless, the Caspian region's relative isolation from world markets, as well as the relative lack of export options, continues to hinder exports outside of the former Soviet republics. Of the 920,000 bbl/d exported from the region in 2001, only about 400,000 was exported to consumers outside of the former Soviet Union.

Natural gas exports from the Caspian region have been even more limited. All of the export pipelines from the region pass through Russia, requiring Caspian region natural gas exporters to make agreements with Gazprom, the Russian monopoly that owns the pipelines, in order to export their natural gas. Since Gazprom is also a competitor with the Caspian region for hard currency natural gas markets, the company has used its position to negotiate better deals and to limit pipeline access for Caspian region natural gas. Turkmenistan's economy, which is concentrated mainly in oil and natural gas,

experienced a huge 25.9% decrease in its gross domestic product (GDP) in 1997 when Gazprom denied Turkmenistan access to its pipeline network over a payment dispute.

Since Gazprom has reserved the hard currency markets of Europe for itself by limiting pipeline access for Caspian region natural gas producers, most exports from the region have remained in the Newly Independent States (NIS). Due to the ongoing transition process to a market economic system in much of the NIS, the majority of these former Soviet republics have been unable to pay existing world prices for natural gas supplies. Thus, in order to export their natural gas at all, the Caspian region's producers have had two options: either sell their natural gas to Russia at below-market prices or pay Gazprom a transit fee, then export those supplies via the Russian pipeline system to ex-Soviet states that cannot pay fully in cash or are tardy with payments for supplies already received.

In 1997, Turkmenistan and Iran completed the $190 million Korpezhe-Kurt Kui pipeline linking the two countries, thereby becoming the first (and so far, only) natural gas export pipeline from Central Asia to bypass Russia. Although Gazprom and Turkmenistan resolved their pricing dispute in 1998, in order to reach its full natural gas export potential, Turkmenistan and other Caspian region natural gas producers must solve the problem of how to pipe their natural gas to consumers and receive hard currency at market prices in return.

New Export Options

In order to bring much-needed hard currency into their economies, Caspian region oil and natural gas producers are seeking to diversify their export options to reach new markets. With new production coming online as well, new transportation routes will be necessary to carry Caspian oil and natural gas to world markets. To handle all the region's oil that is slated for export, a number of Caspian region oil export pipelines are being developed or are under consideration. Likewise, there are several Caspian region natural gas

export pipelines that have been proposed. Although there is no lack of export option proposals, questions remain as to *where* all these exports should go.

West?

The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk Road) was launched at a European Union (EU) conference in 1993. The EU conference brought together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an West-East axis from Europe, across the Black Sea, through the Caucasus and the Caspian Sea to Central Asia.

In September 1998, twelve countries (including Azerbaijan, Bulgaria, Kazakhstan, Romania, Turkey, and Uzbekistan) signed a multilateral agreement known as the Baku Declaration to develop the transport corridor through closer economic integration of member countries, rehabilitation and development of new transportation infrastructure, and by fostering stability and trust in the region. The planned Baku-Ceyhan Main Export Pipeline to transport oil from Azerbaijan to Turkey and then to European consumers is the main component of this cooperation.

In addition, the EU has sponsored the Interstate Oil and Gas Transport to Europe (INOGATE) program, which appraises oil and natural gas exports routes from Central Asia and the Caspian, and routes for shipping energy to Europe. INOGATE is run through the EU's Technical Assistance to the Commonwealth of Independent States (TACIS) program.

East?

However, there is some question as to whether Europe is the right destination for Caspian oil and natural gas. Oil demand over the next 10 to 15 years in Europe is expected to grow by little more than 1 million bbl/d. Oil exports eastward, on the other hand, could serve Asian markets, where demand for oil is expected to grow by 10 million bbl/d over the next 10 to 15 years. In particular, Chinese oil consumption is projected to rise dramatically.

To supply this Asian demand, though, would necessitate building some of the world's longest pipelines. Geographical considerations would force any pipelines to head north of the impassable mountains of Kyrgyzstan and Tajikistan across the vast, desolate Kazakh steppe, thereby adding even more length (and cost) to any eastward pipelines.

South?

An additional way for Caspian region exporters to supply Asian demand would be to pipe oil and natural gas south. This would mean sending oil and natural gas through either Afghanistan or Iran. The Afghanistan option, which Turkmenistan has been promoting, would entail building pipelines across war-ravaged Afghan territory to reach markets in Pakistan and possibly India. With the ouster of the Taliban in Afghanistan in December 2001, proposals to build a Trans-Afghan natural gas pipeline and the Central Asian Oil Pipeline have re-emerged, but neither pipeline is realistic in the short-term.

The Iranian route for natural gas would pipe Caspian region natural gas (from Azerbaijan, Uzbekistan, and Turkmenistan) to Iran's southern coast, then eastward to Pakistan, while the oil route would take oil to the Persian Gulf, then load it onto tankers for further trans-shipment. Turkmenistan and Kazakhstan also have initiated low-volume oil "swap" deals with Iran, delivering oil in tankers to refineries in Iran's northern regions in exchange for similar volumes of crude at Iranian ports in the Persian Gulf. However, any significant investment in Iran would be problematic under the Iran and Libya Sanctions Act, which imposes sanctions on non-U.S. companies investing in the Iranian oil and natural gas sectors. U.S. companies already are prohibited from conducting business with Iran under U.S. law.

North or Northwest?

For its part, Russia itself has proposed multiple pipeline routes that utilize Russian oil pipelines to transport oil to new outlets being developed on the Baltic and Black Seas. In addition to the Caspian Pipeline Consortium's Tengiz-Novorossiisk pipeline, Russia's Baltic Pipeline System became

operational in December 2001, and the country is working with Croatia to connect the Adria pipeline with the southern Druzhba pipeline. Reversing the flows in the Adria pipeline and tying it to the southern Druzhba route will allow oil exports from the Caspian to run via Russia's pipeline system, across Ukraine and Hungary, and then terminate at the Croatian deep-sea Adriatic port of Omisalj.

In addition, Russia already has the most extensive natural gas network in the region, and the system's capacity could be increased to allow for additional Caspian region natural gas exports via Russia. However, there are political and security questions as to whether the newly independent states of the former Soviet Union should rely on Russia (or any other country) as their sole export outlet, and Caspian region producers already have expressed their desire to diversify their export options.

Bosporus/Black Sea Issues

A major problem with additional Caspian oil exports heading west is the increasing congestion in the Bosporus Straits. Turkey has raised concerns about the ability of the Bosporus Straits, already a major chokepoint for oil tankers, to handle additional tanker traffic. Most of the existing Russian oil export pipelines terminate at the Russian Black Sea port of Novorossiisk, requiring tankers to transit the Black Sea and pass through the Bosporus Straits in order to gain access to the Mediterranean and world markets.

Already, Turkey has stated its environmental concerns about a possible collision (and ensuing oil spill) in the Straits as a result of increased tanker traffic from the launch of the Caspian Pipeline Consortium's Tengiz-Novorossiisk pipeline in March 2001. The first tanker with CPC oil was loaded at Novorossiisk in October 2001, and exports are expected to increase to 400,000 bbl/d by the end of 2002. As a result, there already are a number of options under consideration for oil transiting the Black Sea to bypass the Bosporus Straits.

Regional Conflicts

In almost any direction, Caspian region export pipelines may be subject to regional conflicts, an additional complication in determining final routes. Despite the ouster of the Taliban government in December 2001, Afghanistan remains scarred and unstable after 23 years of war. The Azerbaijan-Armenia war over the Armenian-populated Nagorno-Karabakh enclave in Azerbaijan has yet to be resolved. Separatist conflicts in Abkhazia and Ossetia in Georgia flared in the mid-1990's. Russia's war with Chechnya has devastated the region around Grozny in southern Russia. In addition, the Uzbek government has been cracking down on Islamic fundamentalism in Uzbekistan, tensions between rivals Pakistan and India remain high, and the Caspian littoral states themselves have taken to bickering over territorial claims in the Sea.

Nevertheless, several export pipelines from the Caspian region already are completed or under construction, and Caspian region exports are already transiting the Caucasus. While the hope is that export pipelines will provide an economic boost to the region, thereby bringing peace and prosperity to the troubled Caucasus and Caspian regions in the long run, the fear is that in the short-term, the fierce competition over pipeline routes and export options will lead to greater instability.

Sources for this report include: Agence France Presse, BBC Monitoring Central Asia Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian

Economic Outlook, The Economist, Environment News Service, The Financial Times, FSU Oil and Gas Monitor, Hart's European Fuels News, Interfax News Agency, The Moscow Times, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, The Times of Central Asia, Turkish Business News, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, and U.S. Department of State.

LINKS

For more information from EIA on the Caspian Sea Region, please see:
EIA: Caspian Sea Region
EIA: Country Information on Azerbaijan
EIA: Country Information on Iran
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Links to other U.S. government sites:
U.S. Agency for International Development
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Library of Congress Country Study on Iran
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Turkey

Turkey's strategic location makes it a natural "energy bridge" between major oil producing areas in the Middle East and Caspian Sea regions on the one hand, and consumer markets in Europe on the other. Turkey's port of Ceyhan is an important outlet both for current Iraqi oil exports as well as for potential future Caspian oil exports. Turkey's Bosporus Straits are a major shipping "choke point" between the Black and Mediterranean Seas. Finally, Turkey is a rapidly growing energy consumer in its own right.

Note: Information contained in this report is the best available as of July 2002 and can change.

RECENT DEVELOPMENTS

Turkey is currently attempting to recover from a severe economic contraction. After years of steady economic growth (3.7% annually between 1991 and 2000, with a decline in 1999 due to two severe earthquakes), Turkey's economic situation deteriorated sharply in February 2001 as a devastating financial crisis forced the country to sharply devalue its currency, the lira. In addition, Turkey's inflation and unemployment soared, and real gross domestic product (GDP) fell sharply (down 7.3% in 2001). Turkey's crisis was triggered in part by underlying structural weaknesses (i.e., current account deficits, serious problems in the country's banking sector, political instability). The September 2001 terrorist attacks on the United States further exacerbated Turkey's problems, with the International Monetary Fund (IMF) pointing in particular to "lower export demand, loss of tourism receipts, reduced access to international financial markets, and weaker privatization and foreign direct investment prospects."

In response to Turkey's economic problems, the IMF has announced a series of "stand-by credits." An IMF assistance package begun in December 1999 ultimately disbursed around $15 billion to Turkey. This was followed by a further, $17 billion assistance package, approved by the IMF on February 4, 2002 (as of June 28, 2002, Turkey had drawn about $11 billion of this total). IMF assistance to Turkey is conditioned on implementation of a variety of reform measures aimed at addressing the root causes of the country's economic problems. Among other things, Turkey has pledged to cut state spending and subsidies, reform the country's banking sector, privatize state-owned industries, lower the inflation rate, reduce the country's heavy debt burden, and in general create "a stable macroeconomic environment

conducive to economic growth." On July 18, 2002, the IMF stated that Turkey's economic stabilization and reform program was "broadly on track," although this appears optimistic given the country's difficulties meeting its fiscal targets. For 2002, Turkey's real GDP is expected to grow by about 2.6%, with an inflation rate of 41%.

Even prior to its recent economic crisis, Turkey faced numerous economic challenges, including: a large "underground" economy (estimated at 30%-100% of the reported economy); sharp income inequalities (between urban and rural areas in particular); low levels of private investment (Turkey hopes to increase this dramatically); a large, inefficient state sector; overly complicated legal and administrative procedures; a lack of foreign investment; and a failure to generate sufficient jobs for the country's rapidly growing population. Turkey also faces political instability, including a contentious coalition government and intense disagreement over key economic reforms required by the IMF. In addition, Turkey's desire to join the European Union (EU) has increased political debate over such issues as rights for ethnic Kurds, the death penalty and human rights, emergency rule in four eastern provinces, and democracy in general. On July 16, 2002, Turkey's governing coalition (led by Prime Minister Bulent Ecevit's Democratic Left Party -- DSP) effectively lost its majority in Parliament, with new elections being set for early November 2002.

ENERGY

Despite growth in Turkey's private sector in recent years, developments in the country's energy industry are still heavily influenced by the central government. The main energy decision-making body is the Ministry of Energy and Natural Resources (ETKB), currently headed by Zeki Cakan. Cakan replaced Cumhur Ersumer after Ersumer resigned in April 2001 due to the "white energy" corruption scandal over awards for power plant projects as well as for parts of the giant "Blue Stream" gas pipeline project (see below for more details on "Blue Stream"). In July 2002, three high-ranking former Turkish energy officials were found guilty of rigging state power contracts and taking bribes as part of this scandal. The three men were sentenced to

prison.

Prior to Turkey's recent severe economic difficulties, the country's energy consumption had been growing much faster than its production, making Turkey a rapidly growing energy importer. Assuming that the Turkish economy and energy demand return to a rapid growth path, Turkey will require billions of dollars worth of investments in coming years. On April 5, 2001, Turkey announced that it had ratified the Energy Charter Treaty, the international legal framework for energy investment. Also, in early 2001, the Turkish parliament passed an energy liberalization law aimed at ending the government's monopoly in the energy sector, and also geared towards attracting foreign energy investment. In late 2001, Turkey established the Energy Market Board and named Yusuf Gunay as its first energy regulator.

OIL

In general, Turkish oil consumption has increased in recent years, although the country's recent economic recession plus price deregulation measures (which have raised the price of many oil products) since June 1999 appear to have interrupted this trend for the time being. During the first four months of 2002, for instance, it appears that Turkish oil consumption and imports were down approximately 60,000 barrels per day (bbl/d) from the same period in 2000. In the long-run, Turkish oil demand and imports are expected to resume steady growth. Oil provides around 42% of Turkey's total energy requirements, but its share is declining (as the share of natural gas rises). Around 90% of Turkey's oil supplies are imported, mainly from the Middle East (Saudi Arabia, Iran, Iraq, Syria) and Russia. Turkey's port of Ceyhan is a major outlet for Iraqi oil exports, with pipeline capacity from Iraq about 1.2 million bbl/d.

Turkey's oil production is accounted for primarily by three companies -- the Turkish State Petroleum Company (TPAO), and foreign operators Royal Dutch/Shell (Shell) and ExxonMobil. Smaller companies include Petrom of Romania (produces around 2,600 bbl/d in the Selmo block) and Aladdin Middle East (480 bbl/d in Siirt and Gaziantep). TPAO alone accounts for

about 80% of the country's total oil output (currently around 56,000 bbl/d, down from 90,000 bbl/d in 1991). Turkish oil fields are generally small, and scattered around the country. Oil fields in the country's southeast (specifically the Hakkari Basin, Turkey's main oil producing area) are generally old and expensive to exploit. In addition to the Hakkari Basin, Turkey contains oil prospects in its European provinces, in the Black Sea shelf region, and in other oil basins in southern and southeastern Turkey. Potential oil reserves in the Aegean Sea have not been explored due to conflicting Greek claims over the area.

In September 1994, TPAO became part of the Azerbaijan International Operating Company (AIOC), a consortium of foreign oil companies in a multi-billion dollar oil production-sharing agreement with Azeri state oil company SOCAR to develop three offshore oil fields in the Caspian Sea region. TPAO holds a 6.75% share in AIOC. TPAO has established an oil exploration company in Kazakhstan (Kazakhturkmunay) as well, and also is active in other areas of the world, including the Middle East and North Africa.

For several years, it has been reported that as much as 100,000 bbl/d of oil and oil products were being smuggled into Turkey via tanker truck, mainly from northern Iraq. This "border trade" costs the Turkish treasury millions of dollars in lost tax revenue. In March 2000, Turkey's National Security Council (MGK), concerned at lost tax revenues as well as harm to state companies Petrol Ofisis (Poas, the country's largest fuel retailer) and Tupras (which controls 85% of Turkey's refining capacity), imposed controls on petroleum product smuggling from Kurdish areas of northern Iraq, Iran, Georgia, the Azeri enclave of Nakhchevan, Syria, and Bulgaria. A previous crackdown on smuggling in May 1999 reportedly had little effect. On September 18, 2001, Turkey reportedly stopped the diesel oil trade at the Habur border gate with Iraq, but allowed it to restart on January 7, 2002.

In May 2002, a major petroleum market reform bill was sent to Turkey's parliament. If enacted, the law will liberalize pricing of oil and oil products as well as integrate pipeline, refining, and distribution functions. Tupras and

Poas are to be privatized as well.

Pipelines

Oil and gas transportation is a crucial and contentious issue in the Caspian Sea/Central Asia regions. Turkey and the United States have pushed for a "Western route" pipeline that will carry oil from Azerbaijan's port of Baku through Azerbaijan and Georgia and then across Turkey to Ceyhan. The planned 1-million-bbl/d capacity, "Main Export Pipeline" will stretch approximately 1,038 miles (281 miles through Azerbaijan, 135 miles through Georgia, and 622 miles through Turkey) and is expected to cost $2.8-$2.9 billion to construct. Despite initial opposition to the pipeline, which several oil companies criticized as too costly and uneconomical with the planned volumes from Azerbaijan, construction on the Turkish section of the pipeline began in June 2002. The entire pipeline is expected to be finished in late 2004, with the first tanker leaving Ceyhan with Azeri oil in January 2005.

Russia, on the other hand, has promoted a "Northern route" across the Caucasus to the Russian Black Sea port of Novorossiisk. In March 2001, the Caspian Pipeline Consortium (CPC) commissioned the 990-mile, $2.5 billion, 1.34 million-bbl/d-capacity pipeline. From there, oil is transported through the Bosporus Straits. Preliminary plans are to increase exports via the CPC pipeline to 520,000 bbl/d in 2003, but the pipeline is not scheduled to reach its full capacity until about 2015. Turkey has raised concerns about the ability of the Bosporus Straits to handle additional tanker traffic that will be necessary to handle the planned volume of Kazakh oil to be exported via the CPC pipeline. Turkey has expressed its concern that the Straits, already a major chokepoint for oil tankers, cannot handle the strain of additional traffic, raising environmental concerns about a collision leading to an oil spill in the Straits. Although Kazakhstan has argued against limiting oil tanker traffic through the Straits, a number of "Bosporus bypass" options are under consideration or being developed in southeastern Europe. In addition, Ukraine already has constructed a new pipeline, the Odessa-Brody pipeline, specifically to transport oil from the Caspian Sea region to European markets.

One advantage which Baku-Ceyhan has over other potential options for Caspian oil transport is that Ceyhan can handle Very Large Crude Carriers (VLCCs), while the ports of Supsa (Georgia) and Novorossiisk (Russia) are restricted to smaller LR-2 tankers which can transit the Bosporus. Another advantage for Ceyhan is that it can remain open all year, compared to Novorossiisk, which is closed up to two months per year due to bad weather. After failing to come to agreement with other energy companies to join the sponsor group, in March 2002 the Azerbaijan State Oil Company (SOCAR) reduced its stake in the pipeline project to 25%, distributing 20% among other group members. In June 2002, SOCAR sold an additional 5% share to TotalFinaElf (France-Belgium), but rejected a proposal from ChevronTexaco to join the sponsor group. At the end of June 2002, the head of the sponsorship group, Michael Townshend of BP, said that the pipeline ownership group was complete. Shares in MEPCO are as follows: BP (38.21%), SOCAR (20%), Unocal (9.58%), Statoil (8.9%), TPAO (7.55%), TotalFinaElf (5%), ENI (5%), Itochu (3.4%), and Saudi Delta Hess (2.36%).

Refining/Downstream

Turkey has refining capacity of 719,275 bbl/d at 6 refineries. Refining and other downstream operations in Turkey are dominated by partly-state-owned company Tupras, which has four main refining complexes: Batman in the southeast, Aliaga near Izmir, Izmit near Istanbul (the country's largest refinery, damaged during the August 1999 earthquake), and the Central Anatolian Refinery at Kirikkale near Ankara. In 2002, Tupras' share of the Turkish fuels and lubricants market was around 78%, with other major retailers including BP, ExxonMobil, TotalFinaElf, Agip, and ConocoPhillips. Tupras is planning a fifth refinery -- a $700-$800 million facility near Yarimca in western Turkey -- to be completed by 2007. Tupras has a modernization program designed to switch output at its refineries towards lighter products. Turkey's sole private refinery is ATAS, near Mersin on the Mediterranean coast, a joint venture of Mobil (51%), Shell (27%), BP Amoco (17%), and local company Marmara Petrol ve Rafineri Isleri AS (5%).

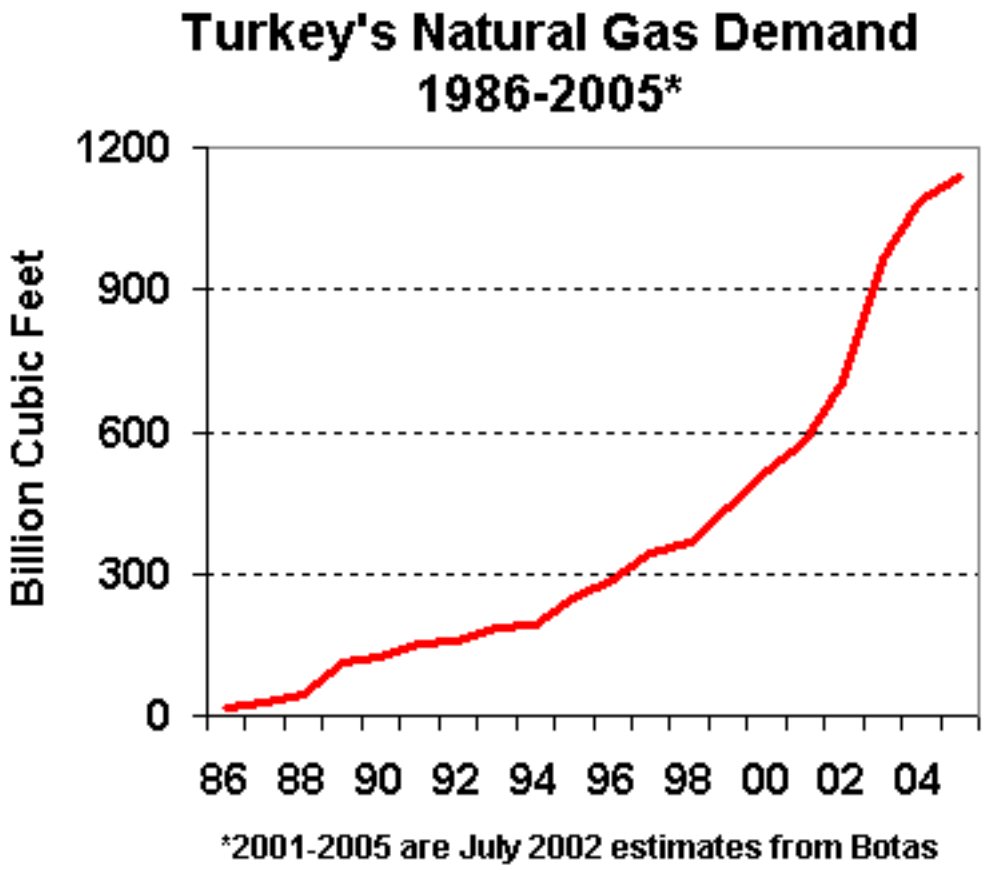
In July 2002, Turkey's government announced that it would sell its 25.8%

share in Poas to the majority shareholder, Is Dogan Petrol Yatirimlari AS. The announcement came amidst calls by the IMF for an acceleration in Turkey's privatization process. In a related development, Turkey's privatization agency stated in early July 2002 that the government hoped to privatize most of the country's energy sector during 2003.

NATURAL GAS

Consumption and Production

Turkey consumed 520 billion cubic feet (Bcf) of natural gas (nearly all imported) in 2000, accounting for around 17% of Turkey's total energy consumption (Turkish gas consumption in 2002 is estimated at around 700 Bcf). Prior to Turkey's recent severe economic problems (plus price deregulation moves), Turkish natural gas demand had been projected to increase extremely rapidly in coming years, with the prime consumers expected to be natural-gas-fired electric power plants and industrial users. Now, however, state natural gas and pipeline company Botas has revised its natural gas demand growth projections down sharply based on Turkey's economic problems. For instance, Turkish natural gas demand had been forecast at about 1.6 trillion cubic feet (Tcf) in 2005, but now is expected to reach only 1.1 Tcf in that year, a 37% downward revision. Many analysts now believe that, given lower Turkish natural gas consumption forecasts, only one of the main import options under development (i.e., Blue Stream, Trans-Caspian Pipeline - TCP, Shah Deniz) -- can be supported for some time.



This sharp downward revision in Turkey's projected natural gas demand could have significant repercussions, since Turkey already has signed contracts for far more natural gas than it is expected to need. To date, Turkey has signed deals for around 2 Tcf per year of natural gas imports beginning in 2005, around three times greater than current Turkish gas consumption. Of this total, over 20% is already coming from Russia via Bulgaria (studies on expanding the Russia-Bulgaria-Turkey "Main Line" are underway), 17% from Iran, and 9% from Algeria and Nigeria combined as liquefied natural gas (LNG). In the future, around one-fourth of Turkey's gas imports are to be supplied from Russia via the Black Sea (see "Blue Stream" below), another quarter from Turkmenistan (beginning in 2005), and about 10% from Azerbaijan (beginning in 2005). Under the "take-or-pay" provisions of natural gas supply contracts with countries like Iran and Russia, Turkey reportedly could be forced to pay cash penalties of up to $1 billion per year if it fails to purchase contracted gas. Already, the National Iranian Gas Company (NIGC) has stated that, if Turkey fails to take the volume of natural gas agreed to for 2002, NIGC will invoke a penalty clause under "take or pay" provisions.

Natural gas is Turkey's preferred fuel for new power plant capacity for several reasons: environmental (gas is less polluting than coal, lignite, or oil); geographic (Turkey is close to huge amounts of gas in the Middle East and Central Asia); economic (Turkey could offset part of its energy import bill

through transit fees it could charge for oil and gas shipments across its territory); and political (Turkey is seeking to strengthen relations with Caspian and Central Asian countries, several of which are potentially large gas exporters). The United States, among others, has been encouraging Turkey to utilize its unique geographical position to become a major transit center for natural gas from the Caspian/Central Asia to Europe. At the same time, however, Turkey's reliance on Russia for gas imports could reach 70% or higher, seemingly undercutting Turkey's goal of diversifying its fuel suppliers.

Turkish natural gas production in 2000 (23 billion cubic feet -- Bcf) met around 4% of domestic natural gas consumption requirements. Major natural gas producers in Turkey include Arco, TPAO and Shell. Marmara Kuzey (North Marmara), which came onstream in May 1997, is the country's largest non-associated gas field. Marmara Kuzey is located offshore in the Thrace-Gallipoli Basin of the Sea of Marmara. In March 2002, the Gocerler natural gas field was officially opened, 16 months after its discovery in the Thrace basin. Production potential is estimated to be as high as 100 Bcf per year. Also, in July 2001, TPAO announced that it had found gas in the Mersin and Iskenderun bays in Turkish areas of the Mediterranean. Currently, most Turkish associated gas is reinjected into oilfields as part of an Enhanced Oil Recovery (EOR) system.

"Blue Stream" Pipeline

On December 15, 1997, Russia and Turkey signed a 25-year deal under which the Russian gas company, Gazprom, would construct a new natural gas export pipeline (called "Blue Stream") to Turkey for delivery capacity of around 565 Bcf annually, with initial deliveries possibly starting in 2002. The $3 billion, 758-mile dual pipeline is slated to run from Izobilnoye in southern Russia, to Dzhugba on the Black Sea, then under the Black Sea for about 247 miles to the Turkish port of Samsun, and on to Ankara.

In March 2002, the first line of "Blue Stream" was completed, with work on the deep-sea portion of the second line begun in June. Construction of the

Turkish onshore section of the pipeline is already complete, while the 222-mile Russian section of the pipeline, which includes compressor stations and underground storage facilities, is scheduled to be finished by September 2002.

Natural gas supplies through the Blue Stream pipeline are slated to begin in October 2002, with Russia scheduled to deliver 70.6 Bcf of natural gas to Turkey via the pipeline this year. By 2009, Blue Stream is expected to reach peak capacity of 565 Bcf per year. Over the course of the 25-year agreement, Turkey will import 14.1 Tcf of natural gas from Russia via Blue Stream. Eventually, the Blue Stream project could be extended onwards to other Mediterranean countries, including Greece.

Other Natural Gas Import Deals

In late January 2002, Iran and Turkey officially inaugurated a much-delayed natural gas pipeline link between the two countries. This follows several years of delays due to economic, political, and technical factors. In 1996, Iran and Turkey had signed a $20 billion agreement that called for Iran to supply Turkey with more than 8 Tcf of natural gas over a period of 22 years beginning in late 1999. Officials in Turkey and Iran variously blamed U.S. sanctions, financing problems on the Turkish leg of the $1.9 billion pipeline, economic recession in Turkey, and delays by the Iranians in completing an important metering station for delaying the project. Exports of Iranian natural gas to Turkey are expected at about 105 Bcf in 2002, rising to 350 Bcf per year by 2007. There are questions, however, whether Turkish demand will grow rapidly enough to absorb this volume of natural gas from Iran, in addition to gas slated to be supplied by Russia, Algeria, and Nigeria.

If Turkish demand does not support the level of natural gas imports for which it has contracted (from Iran and others), Turkey could become an important transit center for natural gas exports to Greece and beyond. Along these lines, Greece and Turkey signed an agreement on March 28, 2002 which calls for extending the natural gas pipeline from Iran to Turkey into Greece. Reportedly, the 177-mile-long pipeline would connect Ankara to Alexandroupolis in northern Greece and would cost $300 million. After that,

natural gas could be transported to Europe via Bulgaria or via an undersea pipeline to Italy, where gas demand -- especially for electric power generation -- is expected to grow rapidly in coming years. A deep water option could be extremely expensive, however, making an overland route more likely.

On May 21, 1999, state natural gas and pipeline company Botas signed an agreement on building a $2-$2.4 billion, 1,050-mile, gas pipeline from Turkmenistan, underneath the Caspian Sea, across Azerbaijan and Georgia (both of which would collect transit fees), and on to Turkey. Gas deliveries of 565-1,060 Bcf per year are possible, with additional gas possibly being sent onwards to Europe. The consortium is led by US company Bechtel and including General Electric, Shell, and PSG International. In mid-July 1999, a top Turkish energy official stated that the TCP from Turkmenistan was still the preferred option for Turkey despite the potentially huge (as high as 35 trillion cubic feet -- Tcf) Shah Deniz gas field in Azerbaijan, which is located hundreds of miles closer (and on the western side of the Caspian Sea) to Turkey than Turkmenistan. Currently, however, progress on the TCP appears stalled, with the international consortium essentially having suspended operations, while Blue Stream proceeds.

Despite previous Turkish government statements that a gas pipeline from Turkmenistan was a top priority, this now seems highly unlikely, as it would compete against the proposed Blue Stream project, as well as against possible gas supplies from Iran and, especially, Azerbaijan. After months of negotiation and delay, Azerbaijan and Turkey signed a long-term natural gas purchase and supply contract on March 12, 2001. Starting in 2005 (delayed one year from the original target date), Azerbaijan will deliver 70 Bcf of natural gas to Turkey in 2005, rising to 177 Bcf in 2007 and around 230 Bcf per year from 2008 through 2020. Natural gas for the deal will come mainly from Azerbaijan's Shah Deniz field, which is scheduled to come online in 2004. In order to deliver this natural gas, it will be necessary to construct a pipeline from Baku to Erzurum in eastern Turkey, where the natural gas will join the Turkish natural gas distribution system. Originally, Azeri officials had hoped to use the existing Soviet-era Gazi-Magomed-Gazakh pipeline, but

technical inspection of the pipeline, along with the planned export volumes, determined that a new pipeline will be necessary.

The Baku-Erzurum pipeline will stretch some 630 miles, including 290 miles in Azerbaijan and approximately 170 miles in both Georgia and Turkey. Currently, the pipeline project is estimated to cost $1 billion. Credits to be drawn from international financial institutions, including the World Bank, European Bank for Reconstruction and Development (EBRD), International Finance Corporation (IFC), and investors from the United States and Japan are expected to cover 70% of the pipeline's construction costs, while shareholders in the development of the Shah Deniz field development will contribute the remaining 30%.

In September 2001, Georgia and Azerbaijan cleared a major hurdle for implementation of the pipeline plan by signing a transit agreement. The Azeri parliament ratified the transit agreement in October 2001, followed by the Georgian parliament in December 2001. In January 2002, Georgia announced it would build two, 88.3-Bcf-capacity underground natural gas storage facilities in the east and southwest of the country as part of the pipeline project.

Construction of the Baku-Erzurum pipeline is scheduled to begin in late 2002, with the pipeline operational by the end of 2004. Initial capacity on the pipeline is slated to be 777 billion cubic feet (Bcf) per year, with capacity eventually rising to 1.06 Tcf per year. With natural gas production in the first stage of exploitation of the Shah Deniz field expected to be 282 Bcf per year, the Baku-Erzurum pipeline will have excess capacity to pipe additional Caspian Sea region natural gas exports, possibly from Turkmenistan if the Caspian littoral states agree on a legal regime for the Sea, allowing the proposed TCP to be built.

Natural gas also could transit Georgia via a proposed north-south pipeline from Russia to eastern Turkey, with one route also passing through Armenia. In November 2000, Georgia approved a project for a 37-mile pipeline to carry

Russian natural gas to Turkey via the Georgian Black Sea coast. After a September 2001 meeting, Georgian officials announced that representatives from Conoco and Turkey's Acsoy Group were ready to invest in the pipeline, which would transport 35.3 Bcf per year of natural gas from Kobuleti, Georgia, to Hopa, Turkey.

Georgia also has held discussions with Gazprom on refurbishing the existing North Caucasus-Transcaucasian natural gas pipeline and extending it into a trans-Georgian pipeline to bring Russian natural gas to Armenia and Turkey. However, this idea has lost some support as Russia focuses on delivering its gas to Turkey via the "Blue Stream" natural gas pipeline under the Black Sea.

Egypt, with huge gas reserves of its own, is another possible source of gas for Turkey, either by pipeline or via LNG tanker. This latter option would include construction of a $1.2-billion liquefaction terminal near Port Said on the Mediterranean coast, and a regasification facility at Izmir in Turkey. Egypt and Turkey signed a preliminary agreement for LNG exports in 1996, but analysts have raised serious questions about whether the project is economically feasible. Also, given the fact that Turkey already has committed to buying more gas than it probably needs for years to come, it is hard to see how Egyptian gas will fit into the picture. Still, new LNG terminals in Turkey are being planned, besides the sole existing, 140-Bcf capacity, terminal adjacent to the existing Marmara Ereglisi combined cycle gas turbine power station. Other possibilities include a regasification terminal at Aliaga (near Izmir on the Aegean Sea), an LNG terminal at Iskenderun on the Mediterranean, and even the world's first floating LNG terminal.

Other Natural Gas Issues

In 2001, Turkey passed legislation which will abolish Botas' monopoly, separating the company into units for natural gas import, transport, storage, and distribution by 2009. At that point, the various components (except for transport) are to be privatized. In the meantime, Botas is to sell off 10% of its market share every year, eventually getting down to 20%.

In July 2002, TPAO said that it would begin negotiations with Germany's Lurgi Oel Gas Chemie on building Turkey's first natural gas storage unit. The facility would be located 50 miles west of Istanbul on the Marmara Sea coast, and will include equipment to for gas purification. Meanwhile, Botas reportedly plans to build another gas storage plant at Salt Lake (Tuz Golu) in central Anatolia.

In February 2002, faced with strong public opposition to a 200% increase in natural gas prices, the Turkish government ordered a price cut of 6% for households and 10% for businesses.

COAL

Turkey has hard coal (anthracite and bituminous) reserves of around 1.1 billion short tons, plus lignite reserves as high as 8 billion short tons. Around 40% of Turkey's lignite is located in the Afsin-Elbistan basin of southeastern Anatolia, while hard coal is mined only in one location -- the Zonguldak basin of northwestern Turkey. Turkey produced 74 million short tons (Mmst) of coal (mainly lignite) in 2000, and consumed 91 Mmst. Between 1990 and 2000, the number of workers in Turkey's coal sector fell from 63,993 to 35,665. Turkish coal is generally of poor quality and highly polluting. It is used mainly for power generation

ELECTRIC POWER

With a young and growing population, low per capita electricity consumption, rapid urbanization and -- until recently -- strong economic growth, Turkey for nearly two decades has been one of the fastest growing power markets in the world. Projections by Turkey's Electricity Generating and Transmission Corporation (TEAS), a public company which owns and operates 15 thermal and 30 hydroelectric plants generating 91% of Turkey's electricity, indicate that rapid (as high as 9%-10% annual) growth in electricity consumption will continue over the next 15 years (although power demand looks weak for now). With electricity shortages, brownouts, and blackouts already common (in part the result of generation and distribution losses as high as 30%, and in part the result of underinvestment), increasing the country's electricity

generating capacity therefore is a top priority for Turkish energy officials. According to the Ministry of Energy and Natural Resources (MENR), meeting Turkey's power needs could require investments of $4-$4.5 billion per year, much of which would need to come from the private sector. Currently, Turkey has plans for an additional 23,603 megawatts (MW) in power generating capacity by 2020, nearly double the country's 26,226 MW current capacity.

A major dilemma now faced by Turkey is how to invest in new electric power capacity while at the same time adhering to foreign debt ceilings mandated under lending rules set by the IMF. Conventional financing of major infrastructure projects would only increase the amount of foreign credit, thus MENR has conceived other options for financing projects. One option used until now has been the so-called Build, Operate and Transfer (BOT) model, under which private investors build and operate private sector generation facilities for a set number of years, at which point they transfer ownership to the state. First introduced in 1984 (under Law 3096) by then Prime Minister Turgat Ozal, BOT projects have been plagued by legal problems, which has slowed their implementation. In January 2001, the Turkish energy ministry announced 29 BOT power projects, worth $1.5 billion, that are to be the last benefiting from treasury guarantees. The projects are mainly wind and small hydro facilities, with a combined generating capacity of 1,379 MW.

In February 2001, Turkey passed the long-anticipated Electricity Market Law, which paves the way for a free market in power generation and distribution in the country. Among other things, the legislation (which President Sezer signed into law in July 2001) calls for: 1) TEAS to be broken up into separate generation, distribution, and trade companies; 2) trade and generation companies to be privatized, while transmission remains in state hands; and 3) a new regulatory board to be set up which will oversee the Turkish power market, set tariffs, issue licenses, and prevent uncompetitive practices. The new law throws into doubt the fate of dozens of BOT and TOR (transfer-of-operating-rights) power projects. In May 2002, the Energy Ministry put six power plants and nine distribution grids on sale.

Germany's Siemens AG is leading a consortium of companies in building a $1.45-billion, 1,300-MW, coal-fired power plant near Iskenderun, in southern Turkey. The plant is scheduled for completion in 2003 and is to burn imported coal. Aside from this large coal-fired facility, Turkey is mainly focused on increased natural gas use for thermal electric power production. GE Power Systems is supplying natural gas-fired turbine generators worth more than $900 million for three new combined cycle power plants (the 770-MW Adapazari, 1,540-MW Gebze, and 1,520-MW Izmir plants). Combined, the three plants are expected to have nearly 4 gigawatts (GW) of power generating capacity when all three become fully operational later this year. GE also reportedly is supplying power generation equipment and services for construction of a $194-million, 206 MW, gas-fired, BOT power plant for Alapi. This plant is scheduled to enter commercial service in late 2002. Several pipeline projects have been proposed to supply gas to these facilities, as well as several LNG terminals. In addition, Botas is expanding its natural gas transmission network along the Black Sea and the Aegean.

In addition to increasing domestically generated electricity through construction of new power plants, Turkey is looking outside its borders to help meet the country's rapidly growing power demand. In May 1999, for instance, Turkish and Turkmen officials reached agreement on power supplies from Turkmenistan. Turkey already is importing around 3 billion kilowatt-hours (bkwh) from Bulgaria annually, and has signed a memorandum with other Black Sea Economic Cooperation (BSEC) members to look into creation of a regional power grid. Turkey also imports power from Russia (via Georgia) and Iran. In September 2000, Turkey reportedly stated its desire to increase its power imports from Bulgaria to 5 bkwh by 2005. In October 2000, Russia signed an agreement with Turkey to increase its power exports to Turkey through Georgia. Besides direct power purchases from other countries, increased natural gas imports will be used largely for electricity generation, with new LNG terminals to be attached to Independent Power Producer (IPP) gas-fired generation facilities.

Turkey has significant hydroelectric power resources (more than 104 total plants, installed capacity over 10.2 GW), and is developing a great deal more, especially as part of the $32-billion Southeast Anatolia -- GAP -- hydropower and irrigation project. When completed, GAP, which is considered one of the most ambitious water development projects ever undertaken, will include 21 dams, 19 hydro plants (with around 7.5 GW of power generating capacity), and a network of tunnels and irrigation canals. Major Turkish hydro dams as part of the GAP include: Ataturk (2,400 MW capacity); Karakaya (1,800 MW); Ilisu (1,200 MW; the largest hydro project on the Tigris River, but highly controversial due to environmental concerns); Cizre (240 MW); Silvan/Kayser (240 MW); Hakkari (208 MW); Alpaslan II (200 MW); Batman (198 MW); Konaktepe (180 MW); and Karkamis (180 MW).

In July 2000, the Turkish government decided to abandon a planned, but oft-delayed, $4-billion, 1,300-MW nuclear power plant. Three international consortia (AECL of Canada, Westinghouse-Mitsubishi of the United States and Japan, and NPI of France and Germany) had submitted bids to build the plant, which would have been Turkey's first nuclear plant. The project was to have been turnkey and would have been located at Akkuyu, on the southern Mediterranean coast. Reportedly, the plant was killed for financial reasons, although there also had been opposition from environmental and anti-nuclear groups, as well as neighboring countries like Greece. Prime Minister Ecevit said that Turkey was not abandoning nuclear power completely, and would consider building the plant in 10-20 years, particularly if nuclear technology improves.

Turkey is considered to have a large amount of wind, geothermal, and solar power potential. In January 2001, Turkey announced approval for 17 wind and one geothermal BOT power plants. Currently, wind power capacity in Turkey is around 19 MW, with units located all over the country. Potential for wind power may be as high as 120,000 MW, with particularly attractive areas for wind located along Turkey's west coast and in southeastern Anatolia. Solar energy is mainly used for roof-top hot water. Geothermal energy potential is estimated at around 35 GW.

ENVIRONMENT

Turkey's explosive economic growth in the mid-1990s had significant repercussions on the country's environment. Economic growth and energy consumption have gone hand-in-hand, and the effect has been an increasing air pollution in cities that are already suffering from high pollution levels. Although Turkey is beginning to take steps to improve air quality (including a switch towards unleaded gasoline by 2005), the increased number of automobiles on Turkish streets is hampering this effort.

Of special concern to Turkey is the threat of marine pollution, especially from oil transport through the narrow Bosporus Straits. The 12-mile passage is already one of the most difficult in the world to navigate, and increased shipping--from oil and gas imports flowing into Turkey, as well as increased Russian shipping from the Black Sea through the Straits to world markets--raise the possibility of an accident. Collisions in the Straits have resulted in large oil spills, and additional oil shipping from the Caspian Sea region via the Black Sea and the Bosporus could put the Istanbul area at further environmental risk.

Industrial production has meant that Turkey's carbon emissions are on the rise, and Turkey is not a party to the U.N. Framework Convention on Climate Change. Compared to other International Energy Agency countries, Turkey's energy and carbon intensities are low, but per capita energy consumption and per capita carbon emissions are trending upwards.

Turkey has substantial renewable energy resources--especially hydroelectric power--and it is currently constructing a series of dams and hydroelectric power plants. As Turkey looks towards possible European Union membership, it will need to continue utilizing this cleaner energy as a means to achieve sustainable economic development. Turkey also has a great degree of potential for energy efficiency improvements.

COUNTRY OVERVIEW

President: Ahmet Necdet Sezer (since May 5, 2000)
Prime Minister: Bulent Ecevit (since January 11, 1999)
Independence: October 29, 1923 (successor state to the Ottoman Empire)
Population (July 2001E): 66.5 million
Location/Size: Southwest Asia/780,580 sq. km (301,930 sq. mi.), slightly larger than Texas
Major Cities: Ankara (capital), Istanbul, Izmir, Adana
Languages: Turkish (official), Kurdish, Arabic
Ethnic Groups: Turkish (80%), Kurdish (20%)
Religions: Muslim (99.8%, mostly Sunni), other 0.2%
Defense (8/1/98): Army (525,000), Navy (51,000), Air Force (63,000), Coast Guard (2,200), Reserves (378,700)

ECONOMIC OVERVIEW

Economy Minister: Kemal Dervis
Finance Minister: Sumer Oral
Currency: Turkish lira (TL)
Market Exchange Rate (7/25/02): US$1=1,730,000 TL (compared to US1$=640,260 TL on 8/3/00)
Gross Domestic Product (GDP) (2000E, market exchange rates): $200.5 billion
Real GDP Growth Rate (1991-2000 annual average): 3.7% **(2001E):** -7.3% **(2002E):** 2.6%
Consumer Price Inflation Rate (2001E): 54.4% **(2002E):** 40.8%
Unemployment Rate (1Q2002): 11.8%
Current Account Balance (2001E): $3.2 billion **(2002E):** -$3.0 billion
Major Trading Partners: Germany, United States, Italy, France, United Kingdom, Russia
Merchandise Exports (2001E): $35.1 billion (around half going to the EU)
Merchandise Imports (2001E): $39.9 billion
Merchandise Trade Balance (2001E): -$4.8 billion
Major Export Products: Agricultural, textiles, iron, steel

Major Import Products: Oil, machinery, chemicals, iron, steel
Foreign Currency Reserves (non-gold; 6/02): $22.3 billion
Foreign Debt (1Q2002): $117.5 billion

ENERGY OVERVIEW

Minister of Energy and Natural Resources: Zeki Cakan (replaced Cumhur Esumer on May 9, 2001)
Proven Oil Reserves (1/1/02E): 296 million barrels
Oil Production (2001E): 56,142 barrels per day (bbl/d) of which 52,142 bbl/d was crude oil
Oil Consumption (2001E): 617,000 bbl/d
Net Oil Imports (2001E): 560,858 bbl/d
Crude Oil Refining Capacity (1/1/02E): 719,275 bbl/d
Natural Gas Reserves (1/1/02E): 310 billion cubic feet (Bcf)
Natural Gas Production (2000E): 23 Bcf
Natural Gas Consumption (2000E): 520 Bcf (more than triple the 150 Bcf consumed in 1991; estimated 706 Bcf in 2002)
Net Natural Gas Imports (2000E): 497 Bcf
Coal Production (2000E): 74.2 million short tons (Mmst)
Coal Consumption (2000E): 90.8 Mmst
Net Coal Imports (2000E): 16.6 Mmst
Estimated Recoverable Coal (2000E): 4.1 billion short tons
Electric Generation Capacity (2000E): 26 gigawatts (44% hydroelectric, 28% coal/lignite, 18% gas, and 9% fuel oil as of 1998)
Electricity Generation (2000E): 119.2 terawatthours (Twh)
Electricity Consumption (2000E): 114.2 Twh (up sharply from 54.0 Twh in 1991)

ENVIRONMENTAL OVERVIEW

Minister of Environment: Fevzi Aytekin
Total Energy Consumption (2000E): 3.2 quadrillion Btu* (0.8% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 55.0 million metric tons of carbon (0.9% of world total carbon emissions)

Per Capita Energy Consumption (2000E): 47.5 million Btu (vs. U.S. value of 350 million Btu)
Per Capita Carbon Emissions (2000E): 0.8 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 15,533 Btu/$1995 (vs U.S. value of 10,918 Btu/$1995)**
Carbon Intensity (2000E): 0.27 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (1998E): Industrial (51.3%), Residential (26.6%), Transportation (16.3%), Commercial (5.8%)
Sectoral Share of Carbon Emissions (1998E): Industrial (55.5%), Transportation (20.2%), Residential (19.4%), Commercial (5.0%)
Fuel Share of Energy Consumption (2000E): Oil (41.5%), Coal (30.6%), Natural Gas (16.9%)
Fuel Share of Carbon Emissions (1999E): Oil (43.4%), Coal (42.9%), Natural Gas (13.7%)
Renewable Energy Consumption (1998E): 746 trillion Btu* (4% increase from 1997)
Number of People per Motor Vehicle (1998): 12.3 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Turkey is not a signatory to the United Nations Framework Convention on Climate Change or to the Kyoto Protocol.
Major Environmental Issues: Water pollution from dumping of chemicals and detergents; air pollution, particularly in urban areas; deforestation; concern for oil spills from increasing Bosporus ship traffic.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Antarctic Treaty, Biodiversity, Desertification, Hazardous Wastes, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Wetlands and Whaling. Has signed, but not ratified, Antarctic-Environmental Protocol and Environmental Modification. Has not signed the UN Framework Convention on Climate Change.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric

power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 2000

OIL AND GAS INDUSTRIES
State Oil Company: Turkish State Petroleum Company (TPAO)
State Refining Company: Turkish Petroleum Refineries Corporation (Tupras)
State Pipelines and Gas Agency: Botas
State Oil Products Retailer: Petrol Ofisi AS (POAS)
Major Ports: Iskenderun, Istanbul, Mersin, Izmir
Major Oil and Gas Fields: Bati Raman, Karakus, K. Karakus
Major Pipelines: Turkey-Iraq ; Turkey contains 1,078 miles of crude oil pipelines, 1,439 miles of oil product pipelines, and 439 miles of natural gas pipelines
Major Refineries (crude oil capacity): Izmit (251,600 bbl/d), Aliaga-Izmir (226,440 bbl/d), Kirikkale (113,200 bbl/d), Mersin (100,000 bbl/d), Batman-Siirt (22,015 bbl/d); Kahramanmaras (6,000 bbl/d) *Sources for this report include: Agence France Presse; Alexander's Gas and Oil Connections; APS Review Market Trends; Associated Press Newswires; BBC Summary of World Broadc*

Sources for this report include: Agence France Presse; Alexander's Gas and Oil Connections; APS Review Market Trends; Associated Press Newswires; BBC Summary of World Broadcasts; Cambridge Energy Research Associates; CIA World Factbook 2001; CSIS Caspian Energy Update; DRI/WEFA; Deutsche Bank special report, "Turkey: Winning the Gas Import Race;" Dow Jones Newswires; Economist Intelligence Unit Country Reports, ViewsWire; Energy Day; Energy Report; Financial Times; Global Power Report; Hart's European Petroleum Finance Week; Hart's Oil and Gas Investor;

International Energy Agency; International Monetary Fund; International Water Power and Dam Construction; Middle East Economic Digest; National Post (Canada); New York Times; Oil Daily; Oil and Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; Reuters; PR Newswire; Turkish Daily News; Turkish Probe; U.S. Energy Information Administration; Wall Street Journal; Washington Post; World Gas Intelligence; World Markets Online.

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LINKS

For more information from EIA on Turkey, please see:
EIA - Country Information on Turkey

Links to other U.S. government sites:
2001 CIA World Factbook - Turkey
U.S. Department of Energy's Office of Fossil Energy's International section - Turkey
U.S. State Department's Consular Information Sheet - Turkey (April 30, 2002)
US State Department's Country Commercial Guide - Turkey FY 2002
Library of Congress Country Study on Turkey (September 1987)
Information from the U.S. International Trade Administration

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Turkey's Embassy in the U.S.

Information on Turkey's Energy Sector from the Turkish Embassy
Turkey's Ministry of Energy and Natural Resources
Turkey's Ministry of Foreign Affairs
Turkish Petroleum Corporation
Botas Petroleum Pipeline Corporation
Turkish Electricity Distribution Corporation
University of Pennsylvania's Links for Turkey
Black Sea Regional Energy Center - Turkey
MENA Petroleum Bulletin

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Country Analysis Briefs

May 2002

Background | Oil | Natural Gas | Coal | Electricity | Nuclear | Profile | Links

Iran

Iran is OPEC's second largest oil producer and holds 9% of the world's oil reserves and 15% of its natural gas reserves. Additionally, Iran is a focal point for regional security issues.

Information contained in this report is the best available as of May 2002 and is subject to change.

GENERAL BACKGROUND

Iran's economy, which relies heavily on oil export revenues (around 80% of total export earnings, 40%-50% of the government budget, and 10%-20% of GDP), was hit hard by the plunge in oil prices during 1998 and early 1999, but with the rebound in oil prices since then, has recovered somewhat. For 2001, Iran's real GDP grew by around 4.3%; for 2002 it is expected to grow at a slightly lower, 3.5% rate. Relatively high oil export revenues the past year or two have allowed Iran to set up an oil stabilization fund. In early February 2002, there were reports that Iran was considering tapping into the fund.

Despite relatively high oil export revenues, Iran continues to face budgetary pressures, a rapidly growing, young population with limited job prospects and high levels of unemployment; heavy dependence on oil revenues; significant external debt (including a high proportion of short-term debt); high levels of poverty; expensive state subsidies (billions of dollars per year) on many basic goods; a large, inefficient public sector and state monopolies (bonyads, which control at least a quarter of the economy and constitutionally are answerable only to supreme leader Ayatollah Ali Khamenei); international isolation and sanctions. These problems, and the lack of obvious progress in addressing them, have led to growing social unrest in Iran, with street riots taking place in November 2001, and large demonstrations by teachers demanding higher wages in January 2002.

To cope with its economic (and social) problems, Iran's government has proposed a variety of privatization and other restructuring and diversification measures, although these remain politically contentious. Iran also has set up a "stabilization fund" for above-budget oil revenues, which amounted to billions of dollars in 2001. Iran also is supposed to be moving ahead with a plan to unify its two major exchange rates -- official and "floating" -- this year. Finally, Iran has expressed interest in joining the World Trade Organization (WTO), although this would require that significant, and politically problematic, economic reforms be carried out by Iran (in February 2002, the United States blocked Iran's application from moving ahead).

In September 1999, President Khatami announced an ambitious program to privatize several major industries, including communications, post, rail, petrochemicals, and even upstream oil and natural gas to an extent, as part of the "total restructuring" of the Iranian economy called for in the country's latest five-year economic plan (which began in March 2000). The five-year plan also targets the creation of 750,000 new jobs per year, average annual real GDP growth of 6% over the period, reduction in subsidies for basic commodities (bread, rice, sugar, vegetable oil, wheat, fuels), plus a wide range of fiscal and structural reforms. Implementation of these plans, however, has been delayed by lack of domestic political consensus (as well as the Iranian constitution). In November 1999, the powerful (and conservative) "Council of Guardians" rejected a bill which would have exempted foreign companies in an offshore free-trade zone from threats of nationalization. More recently, the Council of Guardians vetoed planned reforms to Iran's mining sector. In August 2001, Iran's new Economy Minister, Tahmasb Mazaheri, called for the creation of a privatization organization, and said that unemployment was unacceptably high.

In February 2002, Iran's Parliament passed legislation to reform the country's tax code, substantially reducing corporate tax rates and possibly adding a value-added tax, among other things. It is feared that these tax reform measures could jeopardize Iran's projections of a 29% increase in tax

revenues in its 2002 budget. However, Iran also is considering the taxation of bonyads for the first time ever. This could raise large sums of money for Iran's treasury, although the organizations likely will prove difficult to tax due to their financial opacity.

Iran is attempting to diversify by investing some of its oil revenues in other areas, including petrochemicals. Iran's non-oil exports appear to have increased significantly in recent years. Iran also is hoping to attract billions of dollars worth of foreign investment to the country by creating a more favorable investment climate (i.e., reduced restrictions and duties on imports, creation of free-trade zones). In May 2001, the Majlis approved the "Law on the Attraction and Protection of Foreign Investment," which aims at encouraging foreign investment by streamlining procedures, guaranteeing profit repatriation, and more. This Law represented the first foreign investment act passed by Iran's legislature since the 1978/79 revolution, and would supercede decades of legislation. However, this legislation has not yet come into effect due to disagreements between reformers and conservatives. In June 2001, the Council of Guardians rejected the bill as passed by the Majlis the previous month. In November 2001, the Majlis passed a second, heavily amended, version of the bill. Although this version was far weaker than the first bill, the Council of Guardians again rejected it (in December 2001). As of May 2002, efforts to encourage foreign investment in Iran remain stalled.

On February 18, 2000, Iran held its sixth parliamentary elections since the 1978/79 revolution, with an overwhelming victory for the reformist coalition. Presidential elections were held in June 2001, and President Khatami won reelection by a wide margin. In July 2001, Iran's cabinet approved formation of a "Supreme Energy Council" (SEC), which would consist of ministers from the oil, energy, economy, commerce, mines and industries ministries, among others. The SEC would play a strategic role in overseeing Iranian energy projects.

Sanctions

The U.S. Iran-Libya Sanctions Act (ILSA) of 1996 imposes mandatory and discretionary sanctions on non-U.S. companies investing more than $20 million annually in the Iranian oil and natural gas sectors. Also, in 1995, President Clinton signed executive orders prohibiting U.S. companies and their foreign subsidiaries from conducting business with Iran, while banning any "contract for the financing of the development of petroleum resources located in Iran." In response, U.S.-based Conoco was forced to abrogate a $550-million contract to develop Iran's offshore Sirri A and E oil and natural gas fields. Following this, France's Total and Malaysia's Petronas were awarded the contract. On August 19, 1997, Executive Order 13059 reaffirmed that virtually all trade and investment activities by U.S. citizens in Iran are prohibited. In March 2000, U.S. Secretary of State Albright announced that the United States would lift certain sanctions against Iranian luxury goods. Other sanctions remain in effect, however. In late July 2001, the U.S. Congress voted overwhelmingly to renew ILSA for five more years. In May 2002, the United States announced that it would review a contract by Canada's Sheer Energy (see below) to develop an Iranian oilfield to determine whether or not it violates ILSA.

OIL

Iran holds 90 billion barrels of proven oil reserves, or roughly 9% of the world's total. The vast majority of Iran's crude oil reserves are located in giant onshore fields in the southwestern Khuzestan region near the Iraqi border and the Persian Gulf. Most of Iran's current oil production is accounted for by the following fields: Ahwaz-Bangestan (250,000 bbl/d currently, with plans to increase to 600,000 bbl/d over the next 8 years at a cost of $3 billion), Marun, Gachsaran, Agha Jari, and Bibi Hakimeh. Most of Iran's crude oil is low in sulfur, with gravities in the 30°-39° API range. During 2001, Iran produced about 3.8 million bbl/d of oil. Iran's current sustainable crude oil production capacity is estimated at around 3.85 million bbl/d, which is more than 650,000 bbl/d above Iran's latest (January 1, 2002) OPEC production quota of 3.186 million bbl/d. In August 2001, Iran's oil minister denied a report (in *Middle East Economic Survey*) that Iranian production had hit 4.1 million bbl/d.

In 2001, Iran consumed an estimated 1.1 million bbl/d of oil and had net exports of around 2.7 million bbl/d Around half of Iran's oil exports go to Asian markets, with the remainder going to Europe and Africa. Iran's domestic oil consumption is increasing rapidly (about 7% per year) as the economy and population grow. In addition, Iran subsidizes the price of oil products heavily, resulting in a large amount of waste and inefficiency in oil consumption. Currently, and in spite of being a major net oil exporter, Iran is forced to spend around $1 billion per year to import oil products (mainly gasoline) which it cannot produce locally.

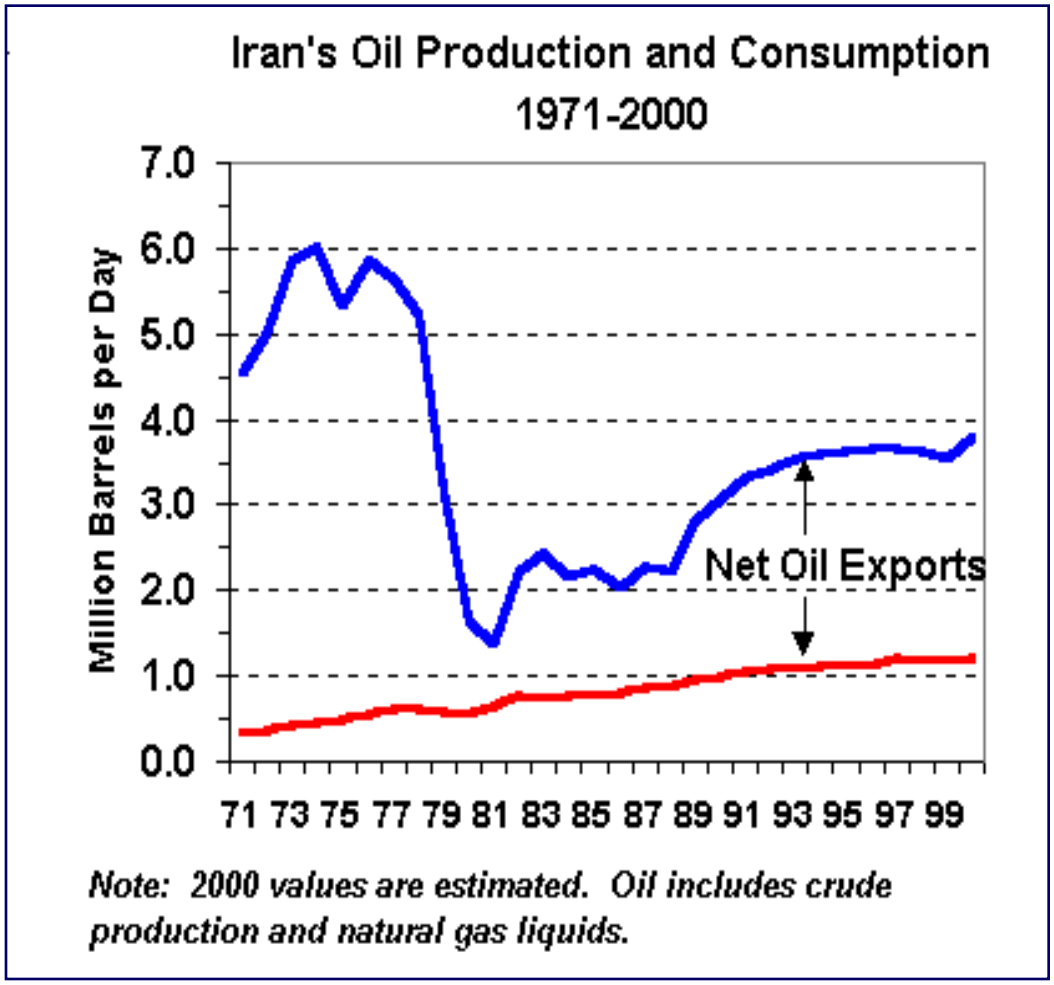
It is possible that with sufficient investment, Iran could increase its oil production capacity significantly. Iran produced 6 million bbl/d in 1974, but has not surpassed 3.8 million bbl/d on an annual basis since the 1978/79 Iranian revolution. During the 1980s, it is believed that Iran may have maintained production levels at some older fields only by using methods which have permanently damaged the fields. Also, Iran's oilfields are -- according to Oil Minister Zanganeh -- experiencing a depletion rate of 250,000-300,000 bbl/d per year, and are in need of upgrading and modernization. Despite these problems, Iran has ambitious plans to double national oil production -- to around 8 million bbl/d -- by 2025 or so, and is counting on foreign investment to accomplish this. Over the next four years, Iran is aiming to double foreign investment in the hydrocarbons sector to $24 billion. The country reportedly also hopes to increase its oil production capacity to 4.5 million bbl/d by 2004.

In October 1999, Iran announced that it had made its biggest oil discovery in 30 years, a giant onshore field called Azadegan located in the southwestern province of Khuzestan, a few miles east of the border with Iraq. According to Iran's Oil Minister Zanganeh, the Azadegan field could contain oil reserves of up to 24 billion barrels, with potential production of 300,000-400,000 bbl/d. On November 1, 2000, agreement was reached between Japan and Iran for Japanese firms (Japex and Indonesia Petroleum, both majority-owned by the Japan National Oil Company -- JNOC) to receive priority negotiating

rights in developing Azadegan. In exchange, Japan is to loan Iran $3 billion; in April 2002, the second $1 billion installment on a $3 billion credit line was disbursed. In January 2001, the Majlis approved development of Azadegan by foreign investors using the so-called "buyback" model (see below). A contract was signed in July 2001.

Since 1995, NIOC has made several sizable oil discoveries, including the huge (3-5 billion barrels) Darkhovin onshore oilfield, located near Abadan and containing low sulfur, 39° API crude oil. In late June 2001, Italy's ENI signed a nearly $1 billion, 5 1/2-year buyback deal to develop Darkhovin, with the added incentive of a limited risk/reward element (payment is to be linked to production capacity). ENI has a 60% stake in the project, with NIOC holding the remaining 40%. Ultimately, production at Darkhovin is expected to reach 160,000 bbl/d.

In February 2001, NIOC announced the discovery of a very large offshore oil field, named Dasht-e Abadan, in shallow waters near the port city of Abadan. According to a top NIOC official, Dasht-e Abadan could contain reserves "comparable" in size to Azadegan.



Foreign Investment/Buybacks

The Iranian constitution prohibits the granting of petroleum rights on a concessionary basis or direct equity stake. However, the 1987 Petroleum Law permits the establishment of contracts between the Ministry of Petroleum, state companies and "local and foreign national persons and legal entities." "Buyback" contracts, for instance, are arrangements in which the contractor funds all investments, receives remuneration from NIOC in the form of an allocated production share, then transfers operation of the field to NIOC after the contract is completed. This system has drawbacks for both sides: by offering a fixed rate of return (usually around 15%-17%), NIOC bears all the risk of low oil prices. If prices drop, NIOC has to sell more oil or natural gas to meet the compensation figure. At the same time, companies have no guarantee that they will be permitted to develop their discoveries, let alone operate them. Finally, companies do not like the short terms of buyback contracts.

The first major project under the buyback investment scheme became operational in October 1998, when the offshore Sirri A oil field (operated by Total and Malaysia's Petronas) began production at 7,000 bbl/d (Sirri A currently is producing around 20,000 bbl/d). The neighboring Sirri E field began production in February 1999, with production at the two fields expected to reach 120,000 bbl/d.

In March 1999, France's Elf Aquitaine and Italy's Eni/Agip were awarded a $1-billion contract for a secondary recovery program at the offshore, 1.5-billion-barrel Doroud oil and natural gas field near Kharg Island. The program is intended to boost production from current levels of around 136,000 bbl/d to as high as 220,000 bbl/d within four years. TotalFinaElf is operator of the project, with a 55% share, while Eni holds the other 45%.

In April 1999, Iran awarded Canada's Bow Valley Energy, along with the former Elf Aquitaine (now TotalFinaElf), a buyback contract to develop the offshore Balal field. The field, which contains some 80 million barrels of reserves, will produce up to 40,000 bbl/d, possibly by the end of 2002. In February 2001, ENI-Agip acquired a 38.25% share in Balal from TotalFinaElf, which continues to hold a 46.75% stake in the field. Bow Valley holds a 15% share.

In November 2000, Norway's Statoil signed a series of agreements with NIOC to explore for oil in the Strait of Hormuz area. The two companies also will cooperate on developing a natural gas-to-liquids processing plant for four southern onshore fields, and possibly will develop the Salman offshore field at a cost of $850 million, with eventual production of 130,000 bbl/d. Iran appears to be accelerating its plans to boost production of natural gas liquids (NGL), as well as liquefied petroleum gas (LPG). NGL expansion plans, including a $500 million plan to build two NGL plans on the south coast of Iran, are aimed mainly at making ethane feedstock available for Iran's growing petrochemical industry.

A much-sought-after deal to develop the giant Bangestan field has been delayed several times after an expected award in 2001. Bangestan includes three oilfields (Anwaz, Mansuri, Ab-Teymour) which currently produce about 250,000 bbl/d of oil. Bidders on a project to raise this oil output to 600,000 bbl/d include TotalFinaElf, Shell, Eni, and BP.

In May 2002, Iran's Oil Ministry signed a $585 million buyback contract with

local company PetroIran to develop the Foroozan and Esfandiar offshore oilfields. PetroIran is expected to increase production at the fields from around 40,000 bbl/d at present to 109,000 bbl/d within 3 years. Iran's Oil Ministry will hold a 51% stake in the project. The two oilfields straddle the border with Saudi Arabia's Lulu and Marjan fields.

In other news related to "buyback" deals, the Cheshmeh-Khosh field, which had been awarded to Spain's Cepsa for $300 million, is likely to be re-awarded to a consortium of Cepsa and OMV. The two companies are to raise crude production at the field from 30,000 bbl/d to 80,000 bbl/d within four years.

Recently, Iran appears to have had some second thoughts about buybacks (including charges of corruption, insufficient benefits to Iran, and also worries that buybacks are attracting too little investment), and reportedly is considering substantial changes in the system. As mentioned above, the July 2001 ENI deal to develop Darkhovin included a limited risk/reward element as an added incentive for foreign investment. In late May 2002, Canada's Sheer Energy became the first foreign company since then to reach a deal ($80 million to develop the Masjed-I-Suleyman, or MIS, field) under the ENI terms. The Sheer deal also was the first since the 9/11 terrorist attacks on the United States, and President Bush's January 2002 State of the Union address in which he labeled Iran as constituting part of an "Axis of Evil." The United States has announced that it will review the Sheer contract to develop MIS to determine whether or not it violates ILSA. Under this deal, Sheer Energy aims to boost MIS production from 4,500 bbl/d to 20,000 bbl/d. In general, however, the addition of a limited risk/reward element has not attracted the flood of foreign energy investment which Iran both needs and wants. As a result, Iran reportedly is considering a further modification to its "buy-back" model, possibly extending the length of such contracts from the current 5-7 years.

Besides economics, new oil and gas deals with foreign companies have been slowed in recent months by an investigation by the conservative judiciary into

Iran's oil ministry. The probe is looking into possible improprieties in $21 billion worth of oil and gas deals signed between 1997 and 2001.

Onshore Developments

NIOC's onshore field development work is concentrated mainly on sustaining output levels from large, aging fields. Consequently, enhanced oil recovery (EOR) programs, including natural gas injection, are underway at a number of fields, including Marun, Karanj, and the presently inactive Parsi fields. EOR programs will require sizeable amounts of natural gas, infrastructure development, and financing.

Although NIOC has run into difficulties in implementing EOR programs at some of its fields mentioned above (i.e., Agha Jari, Binak, Kupal, and Ramshahr) fields, it has been successful in many other cases. One example is NIOC's development work at Gachsaran, which contains in-place reserves of 53 billion barrels and a large-scale natural gas injection capacity which should help increase production.

Offshore Developments

The Doroud 1&2, Salman, Abuzar, Foroozan, and Sirri fields comprised the bulk of Iran's offshore output, all of which is exported. Iran plans extensive development of existing offshore fields and hopes to raise its offshore production capacity to 1.1 million bbl/d by 2003 (from around 600,000 bbl/d now). It is estimated that development of new offshore Persian Gulf and Caspian Sea oil fields will require investment of $8-$10 billion.

The 105-million barrel Balal field, discovered in the 1970s by an ARCO/Murphy consortium, was never developed even though an oil pipeline connecting the field to the Lavan Island export terminal was laid. As mentioned above, Canada's Bow Valley Energy Ltd. is now conducting detailed engineering work, including a 3-D seismic survey, on the Balal field. Balal likely will require extensive water injection and other secondary recovery methods, especially in later years.

On November 14, 1999, Shell announced that it had been chosen for a buyback project to develop the Soroush and Nowrooz offshore oil fields, both of which were closed during the 1980-1988 Iran-Iraq war. These fields are located offshore about 50 miles west of Kharg Island and contain estimated recoverable reserves of around 1 billion barrels of mainly heavy oil. Soroush was one of the original 11 projects put out for tender by NIOC in 1995, and the project calls for Shell to increase output at Soroush-Nowrooz to 150,000 bbl/d by 2003. In late 2001 and early 2002, Shell brought part of the $1.1 billion Soroush-Nowrooz development online, with production at Soroush expected to reach 195,000 bbl/d by 2004. Nowrooz is expected to come online by the end of 2002, with heavy crude production of 60,000 bbl/d expected.

NIOC also would like to develop five oil and natural gas fields in the Hormuz region: Henjam A (known as West Bukha by Oman; the two countries are discussing possible joint development); the A field near Lavan Island; the Esfandir field near Kharg Island; and two structures near the South Pars natural gas field. According to NIOC, the five Henjam fields hold an estimated 400 million barrels of oil and have a production potential of 80,000 bbl/d. Other Iranian oil fields slated for increases include Doroud, Nosrat, Farzam, and Salman (to 130,000 bbl/d by 2004 from 105,000 bbl/d at present).

Caspian Sea Region

Aside from acting as a transit center for other countries' oil and natural gas exports from the Caspian Sea, Iran has potentially significant Caspian reserves of its own, including up to 15 billion barrels of oil and 11 trillion cubic feet of natural gas. It is important to note, however, that almost none of this is "proven" to be recoverable (although preliminary seismic surveys conducted by Lasmo and Shell indicated 2.5 billion barrels of oil). Currently, Iran has no oil or natural gas production in the Caspian region, although in March 2001, NIOC signed a $226-million deal with Sweden's GVA Consultants and Iran's Sadra to build an oil rig in the Caspian Sea off

Mazandaran province. This marks Iran's first exploration attempt in the Caspian Sea, whose legal status among regional states remains in dispute.

At the present time, Iran maintains the most isolated position among the Caspian Sea's littoral states on the division of the Sea. Iran insists that regional treaties signed in 1921 and 1940 between Iran and the former Soviet Union, which call for joint sharing of the Caspian's resources between the two countries, remain valid. Iran has rejected as invalid all unilateral and bilateral agreements on the utilization of the Sea. While Iran agrees that a new legal convention is necessary, Iranian Foreign Minister Kamal Kharrazi told a meeting of deputy foreign ministers of the Caspian states in Tehran in February 2001 that the 1921 and 1940 treaties should be the basis for adopting a new legal regime.

As such, Iran is insisting that either the Sea should be used in common, or its floor and water basin should be divided into equal shares. Iran's preference is for the countries around the Sea to use it by consensus. Under this plan, the so-called "condominium" approach, the development of the Caspian Sea would be undertaken jointly by all of the littoral states. Iran wants all Caspian states to approve any offshore oil developments until the legal status of the Caspian Sea is agreed upon by all of the littoral countries. Another Iranian suggestion is that the littoral states should suspend all work in the Caspian Sea until the new legal status of the Caspian is determined. However, several countries are proceeding with development of subsea resources in what are generally considered to be their national waters, making the condominium approach less likely.

Iran has indicated a willingness to divide the Caspian Sea into national sectors, but only provided there is equal division of the Sea, giving each country 20% of the sea floor and surface of the Caspian. However, using the equidistant method of dividing the seabed on which Kazakhstan, Azerbaijan, and Russia have agreed, Iran would only receive about 12%-13% of the Sea. Both Kazakhstan and Azerbaijan openly have opposed Iran's proposal to divide the Caspian into five equal sectors, stating that that does not

correspond to historical traditions. Nevertheless, Iran continues to insist on receiving 20% of the Sea, and diplomats involved in the working group negotiations have said that Iran has been willing to bide its time in talks in a bid to maximize its share of the Caspian Sea. In March 2002, however, Iran's Oil Minister Zangeneh asserted that Iran would begin exploiting its fifth of the Sea within a short time, and would not permit "any other party to engage in oil exploration" in this area.

As of May 2002, no agreement has been reached among Caspian Sea region states on this matter. In late April 2002, a meeting between the five Caspian littoral states ended without agreement on a new treaty. On May 20, 2002, Iran and Azerbaijan also failed to reach agreement on Caspian Sea division. On July 23, 2001, tensions flared in the Caspian Sea region when an Iranian gunboat intercepted two BP oil exploration vessels off Azerbaijan's coast. Following the incident, BP suspended exploration in the disputed block (which Iran calls Alborz).

Refining and Transportation

As of January 2001, Iran had nine operational refineries with a combined capacity of 1.48 million bbl/d. In order to meet burgeoning domestic demand for middle and light distillates, Iran has imported refined products since 1982, and is attempting to boost its refining capacity to 2 million bbl/d. Two planned grassroots refineries include a 225,000-bbl/d plant at Shah Bahar and a 120,000-bbl/d unit on Qeshm Island. The $3-billion Shah Bahar refinery project was approved by the government in late 1994 and would be built by private investors.

Iran exports crude oil via four main terminals -- Kharg Island (by far the largest), Lavan Island, Sirri Island, and Ras Bahregan. Refined products are exported via the Abadan and Bandar Mahshahr terminals. Many Iranian oil export terminals were damaged during the Iran-Iraq War, but all have been rebuilt. Iran operates the largest oil tanker fleet within OPEC, with 25 ships.

Crude Swaps

In order to get around restrictions in dealing with Iran, several firms have proposed oil "swaps" involving the delivery of Caspian (Azeri, Kazakh, Turkmen) oil to refineries in northern Iran, while the same amount of Iranian oil is exported through Persian Gulf terminals. According to Iranian Oil Minister Bijan Namdar-Zangeneh, Iran is planning to retool its oil infrastructure to accommodate such swaps, including construction of a $400-million, 240-mile pipeline from the Caspian area via Iran's Caspian port of Neka to refineries in northern Iran and to Tehran. In February 2000, the National Iranian Oil Company (NIOC) awarded a Chinese consortium (led by Sinopec and CNPC) a $100-million contract for technical aspects of the project, which is expected to transport 175,000 bbl/d of Caspian crude by the end of 2002, and possibly up to 300,000 bbl/d by late 2003. European oil trading company Vitol is involved in financing the project. Iran also plans to boost capacity at its northern refineries at Arak, Tabriz, and Tehran to about 800,000 bbl/d in order to process this oil. Currently, however, despite capacity of around 50,000 bbl/d, only 15,000-20,000 bbl/d of Turkmen oil are being shipped to Neka, and then on to Tehran by the existing Neka-Tehran pipeline. An equivalent amount of Iranian oil is then made available for export via Kharg Island terminal on the Persian Gulf.

NATURAL GAS

Iran contains an estimated 812 trillion cubic feet (Tcf) in proven natural gas reserves -- the world's second largest and surpassed only by those found in Russia. The bulk of Iranian natural gas reserves are located in non-associated fields, and have not been developed, meaning that Iran has huge potential for gas development. Besides domestic consumption, which is expected to increase more than 70% by 2005, Iran also has the potential to be a large natural gas exporter. In 2000, Iran produced about 2.1 Tcf of natural gas. Currently, natural gas accounts for around nearly half of Iran's total energy consumption, and the government plans billions of dollars worth of further investment in coming years to increase this share.

South Pars

Iran's largest non-associated natural gas field is South Pars, geologically an

extension of Qatar's 380-Tcf North Field. South Pars was first identified in 1988 and originally appraised at 128 Tcf in the early 1990s. Current estimates are that South Pars contains around 280 Tcf of gas, of which a large fraction will be recoverable, and over 17 billion barrels of liquids. Development of South Pars is Iran's largest energy project, and already has attracted around $20 billion in investment. Natural gas from South Pars largely is slated to be shipped north via the planned 56-inch, $500 million, IGAT-3 pipeline (a section of which is now being built by Russian and local contractors), as well as a possible IGAT-4 line, and then reinjected to boost oil output at the mature Aghajari field (output peaked at 1 million bbl/d in 1974, but has since fallen to 200,000 bbl/d), and possibly the Ahwaz and Mansouri fields (which make up part of the huge Bangestan reservoir in the southwest Khuzestan region). South Pars natural gas also could be exported, both by pipeline and possibly by liquefied natural gas (LNG) tanker. Initial gas production from South Pars is expected this year, with sales from the field possibly earning Iran as much as $11 billion per year over 30 years, according to Iran's Oil Ministry.

On September 29, 1997, Total (now TotalFinaElf) signed a $2-billion deal (along with Russia's Gazprom and Malaysia's Petronas) to explore South Pars and to help develop the field during Phase 2 and 3 of its development. NIOC estimates that South Pars has a natural gas production potential of up to 8 billion cubic feet per day (Bcf/d) from four individual reservoirs. Phase 1, which is being handled by Petropars (owned 60% by NIOC), has been delayed several times and now is scheduled for partial completion by the end of 2002 (about 18 months behind schedule), involves production of 900 million cubic feet per day (Mmcf/d) of natural gas and 40,000 bbl/d of condensate. This first phase is being carried out by the Petroleum Development and Engineering Company (PEDEC), an affiliate of NIOC, while TotalFinaElf's consortium is responsible for Phases 2 and 3.

In August 1999, Total signed a $110-million contract with Hyundai Heavy Industries for construction of twin undersea pipelines from South Pars to onshore facilities at Asaluyeh. In March 2002, Hyundai signed another

contract, this one for $1 billion, to build four natural gas processing trains. Eventually, Phases 2 and 3 are expected to produce around 2 Bcf per day of natural gas, and 80,000 bbl/d of condensates. The Asaluyeh facility comprises four natural gas processing trains, sulphur recovery units, condensate stabilization and storage units, and export compressors. In March 2002, TotalFinaElf announced that Phases 2 and 3 of South Pars had begun to come onstream.

Phases 4 and 5, estimated to cost $1.9 billion each, are being handled by ENI and Petropars, and involve construction (by Aip and Petropars) of onshore treatment facilities at the port of Bandar Asaluyeh. These two phases are expected to come online by late 2004 or early 2005. Phases 6 through 8, which are to produce a combined 3 Bcf/d of natural gas and 120,000 bbl/d of condensate, are being handled by Petropars and, in part, by the UK's Enterprise Oil (which acquired a 20% stake in late 2000, but since then expressed interest in pulling out; recently, Enterprise was acquired by Shell Oil). If Enterprise Oil does pull out of South Pars, Norway's Statoil reportedly has signed a Memorandum of Understanding to take its place on Phases 6-8.

Meanwhile, several international bidders reportedly have been short-listed for phases 9 through 12, but little progress has been made to date. Phases 9 and 10 are expected to supply the domestic market while phases 11 and 12 are slated for LNG export and condensate production. Companies reportedly interested in all or parts of phases 9-12 (expected to cost $4 billion) include BP, Eni, TotalFinaElf, and Statoil.

Other Natural Gas Development

In addition to South Pars, the 48-Tcf North Pars development may also be part of Iran's long-term natural gas utilization plans. Development plans call for 3.6 Bcf/d of natural gas production, of which 1.2 Bcf/d would be re-injected into the onshore Gachsaran, Bibi Hakimeh, and Binak oil fields. The other 2.4 Bcf/d would be sent to the more mature Agha Jari oil field. Negotiations on the field stalled in 1995, but Shell reportedly renewed its

interest in 1998. A feasibility study on the field is scheduled to be completed in late 2001, and will determine whether or not North Pars natural gas is needed for injection into mature southern oil fields.

Besides North and South Pars, Iran aims to develop the 6.4-Tcf, non-associated Khuff (Dalan) reservoir of the Salman oil field. Salman straddles Iran's maritime border with Abu Dhabi, where it is known as the Abu Koosh field. NIOC is seeking to develop the Khuff reservoir, which could lead to the production of 500 Mmcf/d of non-associated natural gas, along with the 120,000 bbl/d of crude oil that is now being produced from a shallower reservoir. Salman natural gas could either be exported to Dubai's Jebel Ali or to domestic locations at Qeshm Island and Badar Mogham. The project cost is estimated at slightly under $600 million for a two-platform development.

Iran has made several significant natural gas field discoveries over the past year or so. These include: the 800-Bcf Zireh field in Bushehr province; the 4-Tcf Homa field in southern Fars province; the huge, 14-Tcf Tabnak natural gas field located in southern Iran. Iran's other sizable non-associated natural gas reserves include the offshore 47-Tcf North Pars natural gas field (a separate structure from South Pars), the onshore Nar-Kangan fields, the 13-Tcf Aghar and Dalan fields in Fars province, and the Sarkhoun and Mand fields.

The dual Aghar-Dalan field development has been one of National Iranian Gas Company's recent successful natural gas utilization projects. Since coming online in mid-1995, the Aghar and Dalan fields have produced approximately 600 Mmcf/d and 800 Mmcf/d, respectively. Natural gas from both fields is processed at a $300-million facility at the Dalan field, which is also the location of a 40-MW, natural-gas-fired power plant. Most of the treated natural gas from the Dalan processing plant is carried through a 212-mile pipeline for re-injection in the Marun field and other oil fields in Khuzestan province.

Natural Gas Trade

With almost unlimited natural gas production potential, Iran is looking to export large volumes of gas. Besides Turkey (see below), potential customers for Iranian gas exports include: Ukraine (Kiev reportedly is interested in building an Iran-Armenia-Georgia-Crimea-Ukraine line), Europe (possibly via Ukraine; this offer was reiterated by Ukraine's foreign minister in December 2001), Pakistan, Armenia, Azerbaijan, India, Taiwan, South Korea, and coastal China. Exports could be either via pipeline or by LNG tanker, with possible LNG export terminals at Asaluyeh or Kish Island. Iran reportedly is developing three LNG plants at a cost of $1.5 billion. In December 2001, Iran agreed to build a natural gas pipeline from Khoi in northwestern Iran to Azerbaijan.

In late January 2002, Iran and Turkey officially inauguarated a much-delayed natural gas pipeline link between the two countries. This follows several years of delays due to economic, political, and technical factors. In 1996, Iran and Turkey had signed a $20-billion agreement that called for Iran to supply Turkey with more than 8 Tcf of natural gas over a period of 22 years beginning in late 1999. Officials in Turkey and Iran variously blamed U.S. sanctions, financing problems on the Turkish leg of the $1.9 billion pipeline, economic recession in Turkey, and delays by the Iranians in completing an important metering station for delaying the project. Exports of Iranian natural gas to Turkey are expected at about 105 Bcf in 2002, rising to 350 Bcf per year by 2007. There are questions, however, whether Turkish demand will grow rapidly enough to absorb this volume of gas from Iran, in addition to gas slated to be supplied by Russia, Algeria, and Nigeria. If Turkish demand does not support the level of gas imports for which it has contracted (from Iran and others), Turkey could become an important transit center for natural gas exports to Greece and beyond. Along these lines, Greece and Iran signed a $300 agreement in March 2002 which calls for extending the natural gas pipeline from Iran to Turkey into Greece. Reportedly, the line would connect Ankara to Komotini in northern Greece. After that, gas could be transported to Europe via Bulgaria or via an undersea pipeline to Italy, where gas demand -- especially for electric power generation -- is expected to grow rapidly in coming years. A deep water option could be extremely expensive, however,

making an overland route more likely.

Although India and Iran in 1993 signed a memorandum of understanding on an overland natural gas pipeline, regional political and security concerns to date have blocked completion of a feasibility study. In February 2002, Iran and Pakistan signed a memorandum of understanding on a pre-feasibility study for a possible 1,600-mile gas pipeline from southern Iran to southeastern Pakistan and on to India. Reportedly, Pakistan and Iran at one point had agreed to a natural gas line from South Pars to Multan, Pakistan, with a possible extension to Hazipur-Bijapur-Jagdishpur in northern India. Australia's BHP Billiton is the main foreign backer of the project, which could cost around $4 billion. An offshore route bypassing Pakistan is under study by Snamprogetti of Italy, but this could prove to be far too expensive to be feasible. Pakistan had said in early 2001 that it would allow supplies to cross its territory, and Iran would bear the contractual responsibility for assuring gas supplies to India, but the project does not appear likely to be implemented in the near future. .

Iran has been involved in a border dispute with Kuwait and Saudi Arabia over demarcation of the border through the northern Gulf continental shelf. This region contains the huge (7-13 Tcf) Dorra natural gas field, which Iran had begun drilling in early 2000 but stopped after complaints by Kuwait. Saudi Arabia and Kuwait (which do not recognize Iran's claims to Dorra) signed a bilateral agreement in July 2000 on dividing up the field equally between the two countries. In early 2002, there were reports that Saudi Arabia and Kuwait were planning to develop Dorra even without an agreement with Iran. Besides Kuwait, Iran also is reported to have discussed possible natural gas exports to the United Arab Emirates, although in April 2001, NIOC denied such a plan, as has Crescent Petroleum, the UAE company reportedly involved in the deal.

Besides natural gas exports, Iran also has discussed *importing* natural gas from Azerbaijan, and already imports some natural gas from Turkmenistan. This natural gas is for use in Iran's northern areas, far from the country's main

natural gas reserves in the south. In December 1997, Turkmenistan launched the $190-million Korpezhe-Kurt Kui pipeline to Iran, the first natural gas export pipeline in Central Asia to bypass Russia. The 124-mile pipeline, which had an initial capacity of 141 Bcf, will have a peak capacity of 282 Bcf of natural gas per year. In 2000, Iran imported 106 Bcf from Turkmenistan via the pipeline, with that figure increasing to 154 Bcf in 2001.

According to terms of the 25-year contract between the two countries, Iran will take between 177 Bcf and 212 Bcf of natural gas from Turkmenistan annually, with 35% of Turkmen supplies allocated as payment for Iran's contribution to building the pipeline. In December 2001, the presidents of Turkmenistan and Armenia reached an agreement by which Turkmenistan will supply up to 70.6 Bcf per year of natural gas to Armenia via the Korpezhe-Kurt Kui pipeline and across Iran. Implementation of this deal is contingent on the construction of a long-delayed Iran-Armenia natural gas pipeline (in December 2001, Iran and Armenia signed a deal to build this line at a cost of around $120 million).

ELECTRIC POWER

Iran has installed power generation capacity of about around 31.5 gigawatts (GW), of which the vast majority (80% or so) is natural gas-fired, with the remainder either hydroelectric or oil-fired. As a result of significant state investment in this area, a number of new power plants (mainly hydroelectric and combined cycle) have come online recently in recent years in Iran, including the 2,000-MW Shahid Rai thermal power station in Qazvin; a 1,290-MW combined-cycle plant in Rasht; a doubling of the Tabriz power plant's capacity to 1,500 MW; two, 200-MW, steam-powered units at the Martyr Montazeri plant; a 215-MW steam-powered unit at the Ramin Power Plant; a 107-MW combined cycle generator at Montazer Qa'em Power Plant, three-fourths of the Shazand power plant near Arak in central Iran, and half of the Kerman combined-cycle plant in southeastern Iran.

With power demand growing rapidly (7%-8% annually), Iran is adding significant generation capacity -- both thermal and hydroelectric, with the

goal of reaching a total generating capacity of 40 GW by 2005. The largest hydropower projects are the 3,000-megawatt (MW) Karun 3 plant, the 2,000-MW Godar-e Landar facility, a 1,000-MW station in Upper Gorvand, and the 400-MW Karkheh dam. New thermal projects include two 1,040-MW combined cycle plants in the South, an 1,100-MW combined cycle plant at Arak, and a 1,000-MW facility in Bandar Abbas. In early April 2002, the 1,000-MW, natural-gas-fired, combined-cycle Shahid Raja'i power plant came online in the northern Iranian province of Qazvin.

Iran has received offers for investment in the form of loans and build-operate-transfer (BOT) contracts. BOT contracts allow the investing company to build and operate the generating facility for a period of 15-20 years, after which time the plant is turned over to the Energy Ministry. Negotiations have taken place with international energy firms on expansion plans for power plants at Bandar Abbas, Shaid Rajai, Alborz, Ramin, and Kerman.

Although the government has considered privatization, at present Iran's power sector is run by the state-controlled Tavanir organization. Eventually, Tavanir may be broken up into smaller companies as part of a privatization package. In addition to power generation, Tavanir also is responsible for transmission. Iran has main power distribution networks: 1) The Interconnected Network, which serves all of Iran except for remote eastern and southern areas, using 440-kV and 230-kV transmission lines; 2) the Khorassan Network, which serves the eastern Khorossan province; and 3) the Sistan and Baluchistan Network, which serves the remote southeastern provinces of Sistan and Baluchistan. The government goal is to join these three networks into one national grid. Currently, around 94% of Iranians are connected to one of Iran's power grids. Iran also has power links to neighboring countries, including a recent line connecting Parsabad-e Moghan, Iran, and Imishli, Azerbaijan, and exports small amounts of power. On March 31, 2002, Iran halted power exports to Turkey, reportedly for "commercial reasons." Iran exported approximately 280 million kilowatthours of electricity to Turkey in 2001.

NUCLEAR

Currently, Iran has five small nuclear reactors, one in Tehran and four in Isfahan. Iran claims that its nuclear power is for peaceful purposes and that it will help free up oil and natural gas resources for export, thus generating additional hard-currency revenues. The U.S. State Department frequently has stated U.S. opposition to Iran's nuclear program. The United States has argued that Iran has sufficient oil and natural gas reserves for power generation, and that nuclear reactors are expensive, unnecessary, and could be used for military purposes. Iran is a signatory to the Nuclear Non-Proliferation Treaty.

In March 2001, President Khatami met with Russian President Putin and agreed to expand bilateral cooperation on nuclear power. Russia's atomic ministry has been assisting Iran on the Bushehr nuclear power facility. Work on this plant began in 1974 by West Germany, but was halted (80% complete) following the 1978/1979 revolution. Progress on Bushehr resumed when Russia signed a $780-million contract in 1995, as well as an agreement in September 1998 to complete the facility within 52 months. The 1995 contract with Russia calls for completion of the two, 1,300-MW, pressurized-light water units as well as the supply of two modern VVER-440 units. Since then, work has proceeded slowly. The United States strongly opposes the project and has in the past provided Russia with information pointing to the existence of an Iranian nuclear weapons program. In May 2002, U.S. Energy Secretary Spencer Abraham met with Alexander Rumyantsev, head of Russia's nuclear agency, and discussed this issue, with Rumyantsev stating the Russian position that Bushehr "is not a source of proliferation of nuclear material." Under the latest contract details with Russia, construction on Bushehr must be completed by March 19, 2004. Iran reportedly is to decide during 2002 whether or not to purchase a second Russian-built reactor for Bushehr once the first reactor is finished.

ENVIRONMENT

In the context of its oil-based economy, environmental issues in Iran only recently have become important. Ongoing air pollution in urban areas, which reached a crisis level in Tehran in December 1999, have highlighted the need

to improve Iran's environmental record. The rush to develop oil and natural gas resources in the Caspian Sea makes oil pollution in the Caspian a real environmental threat.

Huge increases in energy consumption over the past 20 years have contributed greatly to pollution levels as Iran's carbon emissions have nearly tripled over the same time span. Large numbers of old, inefficient cars on the road lacking catalytic converters account for much of the country's air pollution. Energy prices are kept artificially low in Iran through heavy state subsidies, resulting in wasteful consumption patterns.

In addition, Iran's abundance of fossil fuel resources has tended to discourage the country's incentive to shift to cleaner alternative energy sources for its energy needs. As Iran continues to struggle with air pollution in the 21st century, however, the country likely will need to take a variety of tough measures in order to avert an environmental crisis.

Sources for this report include: Agence France Presse; AP Worldstream; BBC Summary of World Broadcasts; Calgary Herald; CIA World Factbook 2000; Deutsche Presse-Agentur; Dow Jones; DRI/WEFA; Economist Intelligence Unit Viewswire; Financial Times; Foreign Broadcast Information Service; Gulf News; Hart's Africa Oil and Gas; Hart's Asian Petroleum News; Hart's Middle East Oil and Gas; Interfax; International Herald Tribune; Iran Brief; Middle East Business Intelligence; Middle East Economic Digest; National Post; Nefte Compass, New York Times; Oil and Gas Journal; Oil and Gas Investor; Petroleum Economist; Petroleum Intelligence Weekly; Pipeline and Gas Journal; Reuters; Turkish Daily News; U.S. Energy Information Administration, World Gas Intelligence, World Markets Online.

COUNTRY OVERVIEW

President: Mohammed Khatami (since August 1997; reelected June 2001)
Supreme/Spiritual Leader: Ayatollah Ali Khamenei

Islamic Republic Proclaimed: April 1, 1979
Population (7/01E): 66.1 million
Location/Size: Middle East - between the Persian Gulf and the Caspian Sea/636,296 square miles
Major Cities: Tehran (capital), Meshed, Isfahan, Tabriz, Shiraz, Ahwaz, Kermanshah, Qom, Ardebil, Qazvin
Languages: Persian and Persian dialects (58%), Turkic and Turkic dialects (26%), Kurdish (9%), Luri (2%), Baluch (1%), Arabic (1%), Turkish (1%)
Ethnic Groups: Persian (51%), Azerbaijani (24%), Gilaki and Mazandarani (8%), Kurd (7%), Arab (3%), Lur (2%), Baluch (2%), Turkmen (2%), other (1%)
Religion: Shi'a Muslim (89%), Sunni Muslim (10%), Zoroastrian, Jewish, Christian, and Baha'i (1%)
Defense (8/98): Army (350,000), Revolutionary Guard (120,000), Navy (20,600), Air Force (40,000-45,000), army reserves (350,000)

ECONOMIC OVERVIEW

Minister of Economic Affairs and Finance: Dr. Tahmasb Mazaheri
Currency: Rial (R)
Exchange Rates (5/17/02): R 1,741 per $U.S. for official budget transactions and essential goods imports and exports, as well as external debt service; "floating" Tehran Stock Exchange (TSE) rate of around 8,000 per $U.S.
Gross Domestic Product (GDP, at market exchange rates) (2001E): $82.3 billion
Real GDP Growth Rate (2000E): 5% **(2001E):** 4.3% **(2002F):** 3.5%
Inflation Rate (2000E): 19.2%% **(2001E):** 11.7% **(2002F):** 11.5%
Unemployment Rate (2000E): 12.7% (unofficially, 16%-25%)
Current Account Balance (2000E): $12.6 billion **(2001E):** $7.3 billion **(2002F):** $5.2 billion
Major Trading Partners (2000): Japan, Italy, Germany, China, France, United Arab Emirates
Merchandise Exports (2001E): $24.1 billion
Merchandise Imports (2001E): $16.3 billion
Merchandise Trade Surplus (2001E): $7.8 billion

Major Export Products: Oil and oil products (90%), carpets, pistachios
Major Import Products: Industrial supplies (37%), machinery (30%), consumer goods (18%)
Oil Export Revenues (2001E): $20.5 billion **(2002F):** $16.4 billion
Oil Export Revenues/Total Export Revenues (2001E): around 90%
Total External Debt (3/01E): $21.2 billion

ENERGY OVERVIEW

Minister of Energy: Habibollah Bitaraf
Minister of Petroleum: Bijan Namdar-Zanganeh
Atomic Energy Organization of Iran: Gholamreza Aqazadeh
Proven Oil Reserves (1/1/02E): 89.7 billion barrels
OPEC Crude Oil Production Quota (as of 1/1/02): 3.186 MMBD
Crude Oil Production Capacity (2002E): 3.85 MMBD
Oil Production (2001E): 3.8 MMBD (of which, 3.7 MMBD was crude oil)
Oil Consumption (2001E): 1.1 MMBD
Net Oil Exports (2001E): 2.7 MMBD
Crude Oil Refining Capacity (1/1/02E): 1.48 MMBD
Major Crude Oil Customers: OECD Europe, Japan, China, South Korea
Natural Gas Reserves (1/1/02E): 812 trillion cubic feet (Tcf)
Dry Natural Gas Production (2000E): 2.13 Tcf
Natural Gas Consumption (2000E): 2.22 Tcf
Recoverable Coal Reserves (2000E): 1,885 million short tons (Mmst)
Coal Production (2000E): 1.39 Mmst
Coal Consumption (2000E): 2.15 Mmst
Net Coal Imports (2000E): 0.76 Mmst
Electric Generation Capacity (2001E): 27 gigawatts (around 90% thermal)
Electricity Consumption (2000E): 111.9 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Vice President for Environmental Protection: Dr. Mrs. Masumeh Ebtekar
Total Energy Consumption (2000E): 4.72 quadrillion Btu* (1.2% of world total energy consumption)

Energy-Related Carbon Emissions (2000E): 80.8 million metric tons of carbon (1.3% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 73.8 million Btu (vs U.S. value of 351.1 million Btu)
Per Capita Carbon Emissions (2000E): 1.3 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 39,265 Btu/ $1995 (vs U.S. value of 10,919 Btu/ $1995)**
Carbon Intensity (2000E): 0.68 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (2001E): Residential (31.0%), Industrial (27.0%), Transportation (23.6%), Commercial (8.6%)
Sectoral Share of Carbon Emissions (1998E): Industrial (39.7%), Residential (24.4%), Transportation (27.3%), Commercial (8.6%)
Fuel Share of Energy Consumption (2000E): Natural Gas (49.8%), Oil (47.7%), Coal (1.0%)
Fuel Share of Carbon Emissions (1999E): Oil (57.5%), Natural Gas (41.2%), Coal (1.3%)
Renewable Energy Consumption (1998E): 391 trillion Btu* (300.6% increase from 1997)
Number of People per Motor Vehicle (1998): 27.7 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified July 18th, 1996). Not a signatory to the Kyoto Protocol.
Major Environmental Issues: Air pollution, especially in urban areas, from vehicle emissions, refinery operations, and industrial effluents; deforestation; overgrazing; desertification; oil pollution in the Persian Gulf; inadequate supplies of potable water.
Major International Environmental Agreements: A party to Conventions on Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection and Wetlands. Has signed, but not ratified, Environmental Modification, Law of the Sea and Marine Life Conservation.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 2000

OIL AND GAS INDUSTRIES

Organizations: The Ministry of Petroleum (MoP) has overall responsibility for the country's energy sector. The MoP has four subsidiaries which function autonomously for the most part, but ultimately report to the Ministry: 1) National Iranian Oil Company (NIOC) - oil and gas exploration and production, refining and oil transportation; 2) National Iranian Gas Company (NIGC) - manages gathering, treatment, processing, transmission, distribution, and exports of gas and gas liquids; 3) National Iranian Petrochemical Company (NPC) - handles petrochemical production, distribution, and exports; and 4) National Iranian Oil Refining and Distribution Company (NIORDC) handles oil refining and transportation, with some overlap to NIOC. Also, the National Iranian Tanker Company (NITC) controls the second largest fleet of tankers in OPEC.
Foreign Oil Company Involvement: BG, Bow Valley, BP, ENI, Gazprom, Petronas, Royal Dutch/Shell, Sheer Energy, Statoil, TotalFinaElf
Major Oil Fields: Agha Jari, Ahwaz (Bangestan), Azadegan, Bibi Hakimeh, Darkhovin, Doroud, Gachsaran, Mansouri (Bangestan), Marun, Masjid-e Soleiman, Parsi, Rag-e-Safid, Soroush/Nowruz
Major Refineries (capacity, bbl/d) (1/1/02E): Abadan (400,000), Isfahan (265,000), Bandar Abbas (232,000); Tehran (225,000), Arak (150,000), Tabriz (112,000), Shiraz (40,000), Kermanshah (30,000), Lavan Island (30,000)
Major Oil Terminals: Ganaveh, Kharg Island, Lavan Island, Sirri Island, Cyrus, Ras Bahregan, Larak Island

Gas Pipeline System: IGAT-1 transports associated gas from Khuzestan area oilfields to consumption centers in the north; IGAT-2 transports non-associated gas from the Kangan and Nar fields on the Persian Gulf coast near Bandar Taheri; IGAT-3, which would run from South Pars to Tehran, is planned. Evaluation also has begun on a possible IGAT-4 line from South Pars to industrial northern Iran.

LINKS

For more information on Iran, please see these other sources on the EIA web site:
EIA - Historical Energy Data on Iran
OPEC Fact Sheet

Links to other U.S. government web sites:
2001 CIA World Factbook - Iran
U.S. Treasury Department's Office of Foreign Assets Control
U.S. State Department's Consular Information Sheet - Iran
Library of Congress Country Study on Iran

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The Center for Middle Eastern Studies (University of Texas at Austin) - Iran
Iran Online
Interests Section of the Islamic Republic of Iran in Washington, DC (in the Pakistani Embassy)

Permanent Mission of the Islamic Republic of Iran to the United Nations
Iran: Ministry of Energy
Gulf Wire
Iranian Trade
National Petrochemical Company of Iran
MENA Petroleum Bulletin
Salam Iran Home Page

Iran Weekly Press Digest
Iran Press Service
Pars Times: Iran Oil and Gas Resources
Pars Times: Persian Gulf Region
Pars Times: Caspian Sea Region

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Energy Information Administration

October 2001

Regional Indicators: European Union (EU)

The European Union, with increasingly integrated economies and energy sectors, is the world's second-largest energy consumer (behind the United States). EU members include: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden, and the United Kingdom.

Note: Information contained in this report is the best available as of October 2001 and is subject to change.

BACKGROUND

The European Union (EU) was founded as the European Economic Community (EEC) by the Treaty of Rome in 1957 to promote economic and political integration in Europe. The founding of the EEC followed the creation of the European Coal and Steel Community, established after World War II as a means of promoting integration among former enemies. The EEC has expanded from its original six members (Belgium, France, the Federal Republic of Germany, Italy, Luxembourg, and the Netherlands) to include the United Kingdom, Ireland, and Denmark in 1973; Greece in 1981; Spain and Portugal in 1986; and Austria, Finland, and Sweden (former members of the European Free Trade Association) in 1995. The Treaty on European Union (known as the Maastricht Treaty) ushered in a new stage in European history when it entered into force on November 1, 1993. Maastricht renamed the community (now known as the EU), created European citizenship, strengthened the power of the European Parliament, laid out plans for Economic and Monetary Union (EMU), and committed members to negotiate for expansion of the EU to include Central and Eastern European countries. In 2000, EU members were estimated to account for 29% of world economic activity (see Table 1), a share that remained about constant during the 1990s. The United States has extensive trade relations with the EU. In 2000, 22% of U.S. exports ($152 billion) went to EU members, and 19% of U.S. imports ($195 billion) originated in EU countries.

As part of EMU, 11 EU member countries (Belgium, France, Germany, Italy, Spain, Portugal, Finland, Austria, the Netherlands, Ireland and Luxembourg) adopted a new common European currency, called the "euro," on January 1, 1999. The European Central Bank (ECB) is housed in Frankfurt, Germany. This means that a single monetary policy for the 12 particpating countries is elaborated at the ECB. Euro banknotes and coins are scheduled to begin circulating in all participating countries no later than January 1, 2002, and the euro is to replace completely all participating countries' national currencies by July 1, 2002. Most countries' banks have already been frontloaded with coins and banknotes, starting in September 2001.

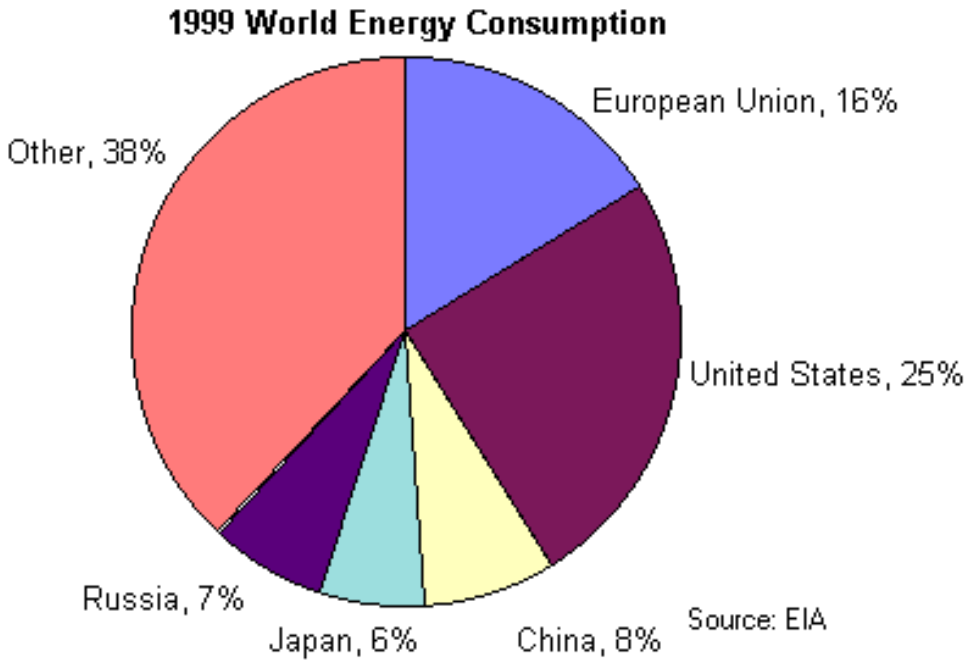
Greece was the only EU member country that applied but was denied entry to EMU at its introduction; in June 2000, Greece's application was accepted and Greece became a member of the euro-zone on January 1, 2001. The United Kingdom and Denmark opted out and Sweden purposely did not meet requirements. The euro-zone represents about 80% of the EU's GDP. The euro currently functions as a base currency for the currencies of all the countries participating in the euro; they are all fixed to the euro, and although the euro is not used as banknotes or coinage, the euro is the only currency that fluctuates in value with other currencies, including the U.S. dollar. The euro fell in value intially against the dollar, from being worth $1.18 in January 1999, to about $1.00 by the end of 1999, and $0.85 in October 2000, before rising again to $0.93 in January 2001. Since then, the euro has stabilized at between $0.93 and $0.85, being valued most recently at $0.91.

In 2001, the Treaty of Nice was signed by member governments. This treaty changes the way the institutions of the EU operate in order to make possible the admission of new member states in the future. Central and Eastern European EU applicants expected to join in the next phase of EU expansion include Poland, Hungary, the Czech Republic, Estonia, Slovenia and Cyprus. Some EU members are calling for a target date by which these applicants will be admitted officially. No date has been set, but membership is expected to extend to these six countries by about 2005. Slovakia, Bulgaria, Romania, Latvia, Lithuania, Turkey and Malta also have begun discussions of accession.

EU legislation has played a significant role in member countries' domestic energy policies. The EU Directive on Electricity was passed in January 1997 and required members to begin opening up their electricity markets to competition within two years (Greece, Belgium and Ireland were granted waivers). The EU Natural Gas Directive was passed in June 1998 (Greece, Belgium,and Ireland again were granted waivers), requiring the opening of EU members' gas markets. The Gas Directive has also affected Norway, as it is a member of the European Economic Area (EEA).

ENERGY CONSUMPTION

In 1999, EU countries consumed 62.7 quadrillion British thermal units (Btu) of energy (16% of the world's total) and generated 915 million metric tons of energy-related carbon emissions (15% of the world's total). Oil is the dominant fuel (see Table 2), accounting for 44% of 1999 total energy consumption in the region, followed by natural gas at 22%. In 1999, EU members consumed about 34% of the world's nuclear power, 18% of the world's oil, 16% of the world's natural gas, and over 10% of the world's coal. Over the past decade, natural gas has been the fastest growing fuel source in the EU, mainly at the expense of coal, whose share has declined sharply. This is in part due to environmental



considerations, but also due to increased availability of natural gas supplies because of pipelines from Algeria, Norway, and Russia. Nuclear power generation has grown only slightly over the past decade. Nuclear power is gradually being phased out in Germany over the next twenty years, so its share of EU energy consumption is likely to drop. Hydroelectric power generation has remained about constant over the past decade. Other "renewables" (geothermal, biomass, solar, wind) doubled between 1992 and 1999, from a relatively small base level. Renewable energy and natural gas are expected to be the two fastest growing fuels in the EU over the next 20 years.

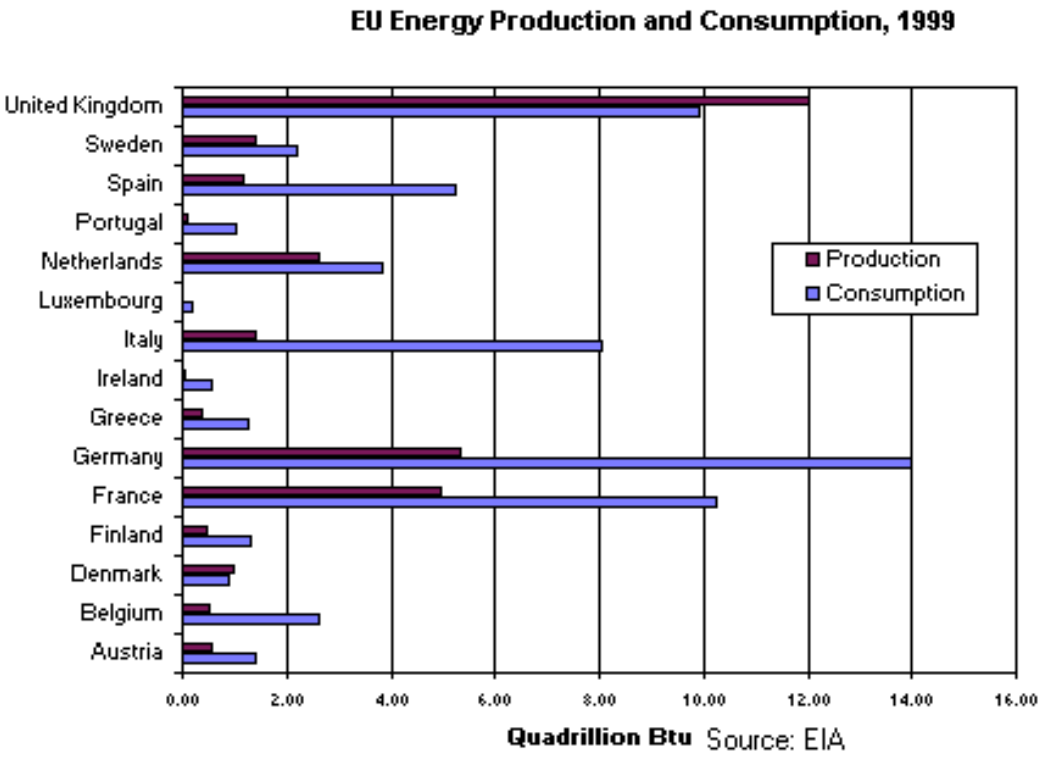
The combined economies of the EU are similar in size to the U.S. economy ($8.5 trillion gross domestic product for the EU in 2000 and $10 trillion for the United States), and the EU population of 379 million exceeds the U.S. population of 278 million. However, EU total energy consumption for 1999 of 63 quads is less than the U.S. consumption of 97 quads.

ENERGY RESOURCES AND SUPPLY

EU members possess only about 0.7% of the world's proven reserves of oil and 2.2% of the world's natural gas reserves (see Table 3). However, they have 7.4% of proven coal reserves, 16% of the world's capacity for refining crude oil into petroleum products, and 16% of the world's electric generating capacity. In 1999, they produced 5% of the world's crude oil, 9% of the world's natural gas, and 8% of the world's coal.

IMPORT DEPENDENCY

The EU region is a net importer of energy. In 1999, while the EU's 15 members consumed 16% of the world's energy, they produced only 8%. Import dependency varies by fuel and individual country, with an overall import dependency for the entire EU of around 50%. In 1999, the EU was a net importer of coal (8% of world production in terms of tonnage vs. 11% of consumption in terms of tonnage); natural gas (9% of world production vs. 16% of consumption); and oil (5% of world production vs. 18% of consumption). Germany, Italy, and France are the EU's largest net importers of energy; the United Kingdom is the only significant net exporter. EU oil is imported primarily from Russia, the Persian Gulf region, Norway, and North Africa.



ENERGY USE AND CARBON EMISSIONS

The 15 EU countries collectively emitted 915 million metric tons (Mmt) of carbon from the consumption of fossil fuels in 1999. This accounted for 15% of world carbon emissions in that year. Of the EU countries, Germany emitted the most carbon (230 Mmt), followed by the United Kingdom (152 Mmt), Italy (121 Mmt) and France (109 Mmt). Overall, the EU emitted 2.4 metric tons of carbon per person in 1999, compared to a U.S. average of 5.6 metric tons per person. Under the December 1997 Kyoto Protocol, the EU is obligated to reduce its greenhouse gas

emissions 8% from 1990 levels (in that year, the EU emitted 913 Mmt of carbon) by 2008-2012. All EU member states signed the Kyoto Protocol on April 29, 1998. On June 17, 1998, the EU agreed on how it would meet the 8% reduction. Under this agreement, different EU member states are assigned varying degrees of emission cuts, ranging from a 4% increase in the case of Sweden, to a reduction of 28% in the case of Luxembourg, with other countries somewhere in between.

Table 1. Economic and Demographic Indicators for EU Countries

	Gross Domestic Product (GDP) (purchasing power parity)				
	2000E (Billions of U.S. Dollars)	Real GDP Growth Rate		Per Capita, 2000E(U.S. Dollars)	Population, 2001E (Millions)
		2000 Estimate	2001 Projection		
Austria	$203	3.1%	2.6%	$25,000	8.2
Belgium	$259.2	4.1%	2.5%	$25,300	10.3
Denmark	$136.2	2.8%	2.2%	$25,500	5.4
Finland	$118.3	5.6%	4%	$22,900	5.2
France	$1,448	3.1%	2.7%	$24,400	59.6
Germany	$1,936	3%	2.4%	$23,400	83
Greece	$181.9	3.8%	3.9%	$17,200	10.6
Ireland	$81.9	9.9%	8.4%	$21,600	3.8
Italy	$1,273	2.7%	2.5%	$22,100	57.7
Luxembourg	15.9	5.7%	5.5%	$36,400	0.4
Netherlands	$388.4	4%	3.2%	$24,400	16
Portugal	$159	2.7%	2.8%	$15,800	10
Spain	$720.8	4%	4.4%	$18,000	40
Sweden	$197	4.3%	2.8%	$22,200	8.9
United Kingdom	$1,360	3%	2.4%	$22,800	59.6
Total	**$8,478.6**	**3.3%**	**2.8%**	**$22,446**	**378.7**

Source: CIA, WEFA World Economic Outlook.

Table 2. Energy Consumption and Carbon Emissions in EU Countries, 1999

	Energy Consumption								Carbon Emissions (Million metric tons)
	Total (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Renewable Electricity	Net Electricity Imports	
Austria	1.39	39%	22%	9%	0%	30%	1%	-1%	18
Belgium	2.61	46%	23%	12%	18%	0.1%	0.4%	0.3%	38

Denmark	0.89	53%	23%	22%	0%	0.03%	5%	-3%	17
Finland	1.31	34%	11%	11%	17%	10%	8%	9%	13
France	10.26	41%	14%	6%	38%	7%	0.2%	-6%	109
Germany	13.98	41%	21%	23%	12%	1%	1%	0.1%	230
Greece	1.28	63%	4%	29%	0%	4%	0.3%	0.1%	26
Ireland	0.56	62%	23%	12%	0%	2%	0.5%	0.4%	10
Italy	8.04	51%	30%	6%	0%	6%	1%	5%	121
Luxembourg	0.19	49%	15%	2%	0%	2%	0.4%	31%	2
Netherlands	3.85	45%	40%	8%	1%	0.03%	1%	5%	64
Portugal	1.02	68%	8%	15%	0%	7%	1%	-1%	17
Spain	5.23	57%	11%	14%	11%	5%	1%	1%	82
Sweden	2.20	34%	1%	4%	30%	33%	1%	-4%	16
United Kingdom	9.92	35%	35%	16%	11%	1%	1%	%	152
Total	**62.73**	**44%**	**22%**	**13%**	**14%**	**5%**	**1%**	**0.4%**	**915**

Source: Energy Information Administration *Note: Percentages may not add to 100% due to independent rounding.*

Table 3. Energy Supply Indicators--EU Countries

	Fossil Fuel Proved Reserves			**Fossil Fuel Production, 1999**				
	Crude Oil, 1/1/01(Million barrels)	**Natural Gas, 1/1/01 (Trillion cubic feet)**	**Coal (Billion short tons)**	**Oil (Crude, liquids, and processing gain; Thousand barrels/day)**	**Natural Gas (Trillion cubic feet)**	**Coal (Million short tons)**	**Electric Generating Capacity, 1/1/99 (Million kilowatts)**	**Crude Oil Refining Capacity, 1/1/01 Thousand barrels/day)**
Austria	86	0.9	0.0	21	0.1	1.3	14	209
Belgium	0	0.0	0.0	12	0.0	0.4	13	768
Denmark	1,069	3.4	0.0	304	0.3	0.0	13	176
Finland	0	0.0	0.0	0	0.0	0.0	16	200
France	145	0.5	0.1	80	0.1	6.3	108	1,895
Germany	380	11.5	73.9	132	0.8	226.1	108	2,259
Greece	10	0.0	3.2	4	0.0	67.2	9	407
Ireland	0	0.7	0.0	1	0.0	0.0	4	71
Italy	622	8.1	0.0	147	0.6	0.0	66	2,359
Luxembourg	0	0.0	0.0	0	0.0	0.0	0	0
Netherlands	107	62.5	0.5	114	2.6	0.0	14	1,204
Portugal	0	0.0	0.0	2	0.0	0.0	10	304
Spain	21	0.0	0.7	20	0.0	26.7	45	1,294
Sweden	0	0.0	0.0	0	0.0	0.0	33	423
U.K.	5,003	26.8	1.7	2,967	3.5	40.9	70	1,771

Total	**7,443**	**114.4**	**80.1**	**3,804**	**8.0**	**368.9**	**523**	**13,340**

Sources: Energy Information Administration, *Oil & Gas Journal*.

Sources for this report include: Energy Information Administration, International Energy Agency; European Union; Oil and Gas Journal.

Links to other U.S. government sites:
International Trade Administration, Country Commercial Guide
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Energy Information Administration

May 2002

Central Asia

Central Asia is gaining in importance to world energy markets, due to the region's vast untapped oil and natural gas reserves. Central Asia's lack of export pipelines, in addition to Central Asia's remoteness from markets, has limited development of natural resources, but foreign investment in Central Asia, particularly in Kazakhstan, could allow the region to reach its energy-producing potential.

Note: Information contained in this report is the best available as of May 2002 and is subject to change.

GENERAL BACKGROUND

With the collapse of the U.S.S.R. in 1991, the Soviet republics of Central Asia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan, became independent for the first time in their history. The Central Asian countries, whose centrally-planned economies were heavily dependent on Soviet subsidies, were unprepared for independence, and their national economies immediately went into a tailspin. The loss of markets and disrupted trading links that accompanied the collapse of the Soviet Union had devastating effects on the Central Asian economies.

Economic and political reforms have proceeded slower in Central Asia than elsewhere in the Commonwealth of Independent States (CIS). Many political leaders in the region are former communists, and autocratic decision-making is still prevalent. Each of the Central Asian countries remains economically tied to Russia, and as a result suffered substantial losses after Russia's August 1998 financial crisis. Since then, the countries of Central Asia have become more competitive economically, and each country has experienced several years of growth. Kazakhstan and Turkmenistan, buoyed by oil and natural gas exports, respectively, have experienced the largest real gross domestic product (GDP) increases. Although Russia still controls much of the region's oil and natural gas export routes, new export options are in development, and energy exports are likely to prove a major driver behind Central Asia's future economic growth.

REGIONAL ENERGY ISSUES

Central Asia's plentiful oil and natural gas reserves have made the region an increasingly important area for world energy supply security. The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk

Road) was launched at a European Union (EU) conference in 1993, bringing together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an east-west axis, leading to increases in oil and natural gas production from Central Asia. Export pipelines, especially for natural gas, are still needed in order to facilitate further increases in Central Asia's energy production.

With the opening of its Caspian Pipeline Consortium (CPC) pipeline, Kazakhstan, for one, is beginning to export more oil to customers outside of the region. However, Central Asia's remoteness from world markets, as well as its lack of infrastructure to export its oil, natural gas, and electricity to customers outside the region, has meant that much of the Central Asia's energy is consumed internally. In addition, under the Soviet Union, much of the region was intertwined economically, and the newly independent Central Asian states in many ways remain dependent on each other, especially for energy supplies. Thus, the Central Asia states each face the dilemma of finding export outlets for their energy supplies at world market prices while also securing inexpensive energy from their neighbors for their own impoverished people.

Oil Exports

Central Asia's biggest oil producer is Kazakhstan, which produced approximately 811,000 barrels per day (bbl/d) in 2001, followed by Turkmenistan (159,000 bbl/d in 2001) and Uzbekistan (137,300 bbl/d in 2001). With its bountiful oil reserves and a relatively business-friendly investment climate, Kazakhstan has attracted substantial foreign investment to its oil sector, providing a significant boost to its oil industry. In addition to the Atyrau-Samaraand CPC export pipelines via Russia, Kazakhstan has a number of oil export options open to it. A number of Caspian Sea region oil export pipelines involving Kazakhstan are in development or under consideration.

Export options for Turkmenistan and Uzbekistan, which is doubly landlocked, are more limited. Turkmenistan has no oil pipelines, meaning that all the crude oil exported from Turkmenistan is shipped by sea. Even after shipping its oil by tanker to Russia's Caspian Sea port of Makhachkala, however, securing pipeline access has been a problem for Turkmenistan. In 2000, Turkmenistan arranged with Russian pipeline company Transneft to export up to 50,000 bbl/d via the Makhachkala link to the Baku-Novorossiisk pipeline. Since Turkmen oil has a relatively high content of sulfur and parrafins and high viscosity, Transneft determined it was not fit for the pipeline.

In order to load the oil into the pipeline, Transneft built the Dagar processing complex so that the heavy Central Asian oil could be mixed with light West Siberian oil and brought up to the Urals export standard. However, oil companies and traders supplying oil from Central Asia refused to use the complex, and Transneft refused to load it, leaving tankers with Turkmen oil standing in port. Turkmenistan eventually accepted rail transportation of its oil. Owing to reduced Kazakh and Azeri oil in the Russian pipeline system, Transneft has relented to accept increased Turkmen oil exports in the Makhachkala-Novorossiisk pipeline in order to utilize more of the pipeline's capacity. Turkmenistan is planning to export about 20,000 bbl/d via Makhachkala in 2002.

Turkmenistan increasingly has turned to swap agreements with Iran in order to export its oil, with Turkmen oil being delivered to the Iranian Caspian port of Neka. The oil swaps began in July 1998. Dragon Oil, which produced approximately 7,000 bbl/d in 2001 in a production-sharing agreement (PSA) with Turkmenistan, has exported its share of this production through a swap deal with Iran since 1998, and in April 2000 the company signed a new 10-year swap agreement with Iran. U.S.economic sanctions on Iran have prohibited American oil companies with investments in Turkmenistan from participating in the oil swaps. Also, any significant investment in an Iranian oil project by a foreign energy company may be subject to the Iran and Libya Sanctions Act, which the U.S. Congress renewed in August 2001.

Uzbekistan's only current oil export option is to reverse an existing crude oil pipeline that brings oil from Omsk, Russia, to Uzbek refineries. Uzbekistan has signed a memorandum of understanding with Turkmenistan, Afghanistan, and

Pakistan to build the Central Asia Oil Pipeline (CAOP), which, if constructed, would transport Uzbek and Turkmen oil via Afghanistan to a proposed new deepwater port at Gwadar on Pakistan's Arabian Sea coast. Continuing unrest in Afghanistan has stalled any progress on the CAOP, and the relatively small volumes of Uzbek oil that will be available for export over the next 10-20 years are insufficient to support the construction of a new export pipeline without additional volumes from other Central Asian countries.

Natural Gas Exports

The five former Soviet Central Asian countries hold nearly 4% of the world's natural gas reserves, and both Uzbekistan and Turkmenistan are already major natural gas producers. In 2000, Uzbekistan produced 1.99 trillion cubic feet (Tcf) of natural gas, followed closely by Turkmenistan, which produced 1.64 Tcf of natural gas in that same year. Although it only produced 314.3 billion cubic feet (Bcf) of natural gas in 2000, Kazakhstan has considerable proven natural gas reserves, and the country's possible reserves in its sector of the Caspian Sea could make Kazakhstan a major natural gas producer in coming years.

As Kazakhstan, Turkmenistan, and Uzbekistan continue to develop their natural gas industries and increase their production, senior Russian officials--including President Vladimir Putin--have called for a Eurasian alliance to offset the impact of European natural gas market liberalization. According to Putin, the so-called "Gas OPEC," uniting Russia with the three big natural gas-producing countries in Central Asia, would "bring an element of stability into the transportation of natural gas on a long-term basis." Analysts have criticized the alliance proposal as a Russian attempt to exercise control over Central Asian natural gas exports.

Central Asia's main natural gas export, the Central Asia-Center pipeline, already is routed into the Russian natural gas pipeline system, as is the Bukhara-Urals pipeline. In an effort to diversify export routes, a number of natural gas pipelines originating in Central Asia are under consideration. In addition to Caspian Sea natural gas export pipeline proposals, such as the Trans-Caspian Gas Pipeline, a pipeline that exports Turkmen natural gas via to Iran, the Korpezhe-Kurt Kui pipeline, has already been constructed, and a proposed Trans-Afghan pipeline is under consideration to export Central Asian natural gas via Afghanistan to Pakistan. Central Asia also has a number of internal pipelines, including the Tashkent-Bishkek-Almaty pipeline, to serve natural gas customers in the region.

Central Asia-Center Pipeline

The Central Asia-Center pipeline, built in 1974, has two branches. The western branch delivers Turkmen natural gas from near the Caspian Sea region to the north, while the eastern branch pipes natural gas from eastern Turkmenistan and southern Uzbekistan in a northwest direction across Uzbekistan. The pipeline branches meet in western Kazakhstan, where they run further directly north and enter the Russian natural gas pipeline system. Turkmenistan has been the chief exporter of natural gas via the Central Asia-Center pipeline, which has a 3.53-Tcf combined capacity.

Over 90% of Turkmenistan's natural gas exports via the pipeline go through the eastern branch, since the majority of Turkmen natural gas production is in the eastern part of the country, and also because the western branch of the pipeline is in poor technical condition. In 2001, Turkmenistan had planned to export 1.41 Tcf of natural gas via the Central Asia-Center pipeline, including 1.06 Tcf to Ukraine and another 353 Bcf to Russia. However, Turkmenistan exported only about 1.16 Tcf via this route, which Turkmen officials attributed to the limited capacity of the Kazakh segment of the pipeline.

Turkmenistan has sought to reconstruct compressor plants and pipeline sections of the western branch that are on its territory, but Turkmen President Saparmurat Niyazov has complained that sections of the pipeline that are in Uzbekistan and Kazakhstan are obsolete and require modernization. According to Turkmenistan, capacity on the Central Asia-Center pipeline is only about 2.4-2.5 Tcf presently due to a lack of maintenance and repair. Turkmenistan has stated that this is restraining its export capacity to the north, since the country could increase its natural gas production if the pipeline's

capacity were increased. In 2002, Turkmenistan is planning to export 1.77 Tcf of natural gas via the Central Asia-Center pipeline, with 1.41 Tcf to be piped via Russia to Ukraine.

Trans-Caspian Gas Pipeline
As part of its strategy to increase its natural gas exports, Turkmenistan is developing alternatives to Russia's pipeline network. Among the proposals is the 1,020-mile Trans-Caspian Gas Pipeline (TCGP), which would run from Turkmenistan under the Caspian Sea to Azerbaijan, through Georgia, and then to Turkey. The pipeline's initial natural gas throughput would be 565 Bcf, eventually rising to 1.1 Tcf.

TCGP has encountered numerous problems, including competition with Azeri and Russian natural gas to supply the Turkish natural gas market. Russia's "Blue Stream" pipeline to Turkey is nearly completed, and construction on the Baku-Erzurum natural gas pipeline is scheduled to begin in 2002. Although Azerbaijan and Turkmenistan resumed talks on the TCGP in October 2001, the lack of a legal framework governing the use of the Caspian Sea continues to complicate the issue of constructing the pipeline. In addition, several of the Caspian littoral states are opposed to trans-Caspian pipelines on environmental grounds.

Korpezhe-Kurt Kui Pipeline
In December 1997, Turkmenistan launched the $190-million Korpezhe-Kurt Kui pipeline to Iran, the first natural gas export pipeline in Central Asia to bypass Russia. The 124-mile pipeline, which had an initial capacity of 141 Bcf, will have a peak capacity of 282 Bcf per year. In 2000, Turkmenistan exported 106 Bcf to Iran via the pipeline, with that figure increasing to 154 Bcf in 2001.

According to terms of the 25-year contract between the two countries, Turkmenistan will pipe between 177 Bcf and 212 Bcf of natural gas to Iran annually, with 35% of Turkmen supplies allocated as payment for Iran's contribution to building the pipeline. In December 2001, the presidents of Turkmenistan and Armenia reached an agreement by which Turkmenistan will supply up to 70.6 Bcf per year to Armenia via the Korpezhe-Kurt Kui pipeline and across Iran. Implementation of this deal is contingent on the construction of a long-delayed Iran-Armenia natural gas pipeline.

Trans-Afghan Pipeline
In October 1997, Unocal set up the Central Asian Gas Pipeline (Centgas) consortium to build a pipeline from Turkmenistan across Afghanistan to Pakistan. However, in early August 1998, Unocal announced that Centgas had not secured the financing necessary to begin the work, and on August 22, 1998, Unocal suspended construction plans for the pipeline due to the continuing civil war in Afghanistan and the U.S. missile attacks on suspected terrorist training camps.

Until recently, the pipeline was considered effectively dead, but with a fragile peace in Afghanistan established and the Taliban removed from power, the idea of a trans-Afghan pipeline has been revived. Under the original plans, the pipeline would run 900 miles from the Turkmen natural gas deposit at Dauletabad through Kandahar, Afghanistan, and terminate in yhe Pakistani city of Multan. Uzbekistan also signed a memorandum of understanding with Turkmenistan, Afghanistan, and Pakistan to participate in the Centgas pipeline project. A 460-mile stretch of the pipeline, which would have a capacity of between 706 Bcf and 1.06 Tcf, would cross Afghan territory. Approximately 12% of the pipeline's capacity would be reserved for Afghan natural gas.

Turkmen President Saparmurat Niyazov and interim Afghan leader Hamid Karzai have expressed their support for the pipeline, which would cost an estimated $2 billion. Uzbek President Islam Karimov is also on record advocating the pipeline. In March 2002, Karzai, Niyazov, and Pakistan President Pervez Musharraf agreed to hold trilateral talks on the pipeline proposal at the end of May 2002.

Tashkent-Bishkek-Almaty Pipeline

Uzbekistan's main natural gas export pipeline has been the Tashkent-Bishkek-Almaty pipeline which runs through northern Kyrgyzstan to southern Kazakhstan. The pipeline is the main source of natural gas for Kyrgyzstan and southern Kazakhstan. Irregular supplies from Uzbekistan, illegal tapping of the pipeline by Kyrgyzstan, and mounting debts by both Kazakhstan and Kyrgyzstan for supplies already received have led to increased tension between the three neighbors. Kyrgyzstan's agreement with Uzbekistan to supply it with water for the growing season, in addition to electricity, in exchange for natural gas supplies has served to complicate relations between the two states.

For its part, Uzbekistan periodically has cut off supplies to Kyrgyzstan in an effort to force Kyrgyzstan to pay its debts for natural gas supplies, which stood at approximately $1.6 million in March 2002. Kyrgyzstan has complained about the supply disruptions, which frequently occur during winter, leaving Kyrgyz consumers without adequate heat and power. Adding to the conflict, in December 2001 Kyrgyz companies illegally took 0.4 Bcf of Uzbek natural gas intended for Kazakhstan. Kyrgyz authorities explained that they had to use the natural gas following the sudden suspension of Uzbek natural gas supplies to Kyrgyzstan.

In December 2001, Kyrgyzstan agreed to turn its section of the pipeline into a concession for 10 years in payment for its debts to Kazakhstan. If Kyrgyzstan had not agreed to give its 90-mile section of the Tashkent-Bishkek-Almaty pipeline in concession, Kazakhstan had drawn up plans to start building a $70-million pipeline to bypass Kyrgyzstan. As a result of Kyrgyzstan's vulnerability to supply disruptions from Uzbekistan, the Kyrgyz government has begun importing more natural gas from Kazakhstan, as well as entered into negotiations with Kazakh and Russian officials about continuing to the construction of a natural gas pipeline from Russia to Kyrgyzstan. Completing the pipeline, whose construction was halted in 1991, would require $60 million.

Kazakh-Uzbek relations also have been strained over natural gas supplies via the Tashkent-Bishkek-Almaty pipeline. Kazakh officials have complained about Uzbekistan's irregular pricing policy. Uztransgaz, Uzbekistan's monopoly natural gas distribution company, repeatedly has attempted to increase its prices for supplies to southern Kazakhstan. According to a February 2002 agreement, Uztransgaz will supply 46 Bcf of Uzbek natural gas to southern Kazakhstan at a price of $40 per 1,000 cubic meters. Earlier, Uztransgaz proposed that Kazakhstan should pay $45 per 1,000 cubic meters. In 2001, Kazakhstan announced its intention to develop the Amangeldy natural gas field in its southern regions in order to end the country's reliance on Uzbek imports.

Other Central Asian Natural Gas Pipelines

Natural gas pipelines also run from Uzbekistan to Tajikistan's capital of Dushanbe, as well as through northern Tajikistan. Tajik and Uzbek officials have been operating under an arrangement where Uzbekistan supplies Tajikistan with natural gas as payment for Uzbekistan's use of a transit pipeline which crosses the Leninabad region of northern Tajikistan and links Uzbekistan's eastern territory with its natural gas fields. Tajikistan has contracted with Uzbekistan for additional natural gas, owing to overconsumption by Tajik consumers, and Tajikgaz, Tajikistan's state natural gas distribution company, has run up a $2 million debt to Uzbekistan for supplies already received.

With the volume of Turkmen natural gas transiting Kazakhstan on the rise, the Bukhara-Urals pipeline has been pressed into service. In March 2001, natural gas transit started on the previously inactive pipeline, with approximately 200 Bcf exported via the pipeline in 2001. KazTransGaz, Kazakhstan's natural gas transportation company, invested about $20 million in modernizing its section of the Bukhara-Urals pipeline system in 2000.

Electricity Exports

Several countries in the Central Asia region have electricity available for export, and there is also substantial untapped hydropower potential in both Kyrgyzstan and Tajikistan. In the Fergana Valley, eastern Uzbekistan, northern Tajikistan, and southern Kyrgyzstan are intertwined geographically, and because their power grids are interconnected, they are able to export power to each other as needed.

In general, Kyrgyzstan and Tajikistan export their seasonal hydropower to Uzbekistan in the summer, when both generate excess electricity, and Uzbekistan supplies Tajikistan and Kyrgyzstan with electricity in winter months. In 2001, Uzbekistan supplied 0.2 billion kilowatt-hours (Bkwh) of electricity to Tajikistan in the winter period, and received 0.3 Bkwh from Tajikistan in the summer. In October 2001, Kyrgyzstan agreed to accept 0.5 Bkwh of electricity in Uzbekistan in exchange for guaranteeing the accumulation of water in its Toktogul water reservoir so that irrigation water will last for Uzbekistan through the growing season in 2002.

Tajikistan, Uzbekistan, and Turkmenistan also have started electricity exports to Afghanistan. In mid-March 2002, Tajikistan began experimental exports to Afghanistan's northern provinces, and in that same month Uzbekistan resumed electricity shipments to Afghanistan, three years after halting deliveries. Under an intergovernmental agreement signed on March 7, 2002, Turkmenistan is set to spend $520 million on projects to export Turkmen electricity to Afghanistan. In the first stage, Turkmenistan will build and overhaul power lines, including the 50-megawatt (MW) Mary-Shibirgan-Mazar-e-Sharif line. In the second stage, the power line will be extended to Kabul and power capacity will increase to 200 MW. A Mary-Serkhetabat-Herat-Kandahar power line also will be built with a 200-MW capacity.

Table 1. Economic and Demographic Indicators for Central Asia

Country	Gross Domestic Product (Nominal GDP), 2001E (Billions of U.S. $)	Real GDP Growth Rate, 2001 Estimate	Real GDP Growth Rate, 2002 Projection	Per Capita GDP, 2001E	Population 2001E (Millions)
Kazakhstan	$21.4	13.2%	7.0%	$1,442	14.8
Kyrgyzstan	$1.5	6.6%	5.3%	$290	5.0
Tajikistan	$1.0	9.5%	7.5%	$152	6.3
Turkmenistan	$5.4	18.0%	13.0%	$988	5.5
Uzbekistan	$10.8	4.3%	4.4%	$428	25.3
Total/weighted average	$40.1	11.1%	7.1%	$705	56.9

Source: DRI/WEFA

Table 2. Energy Consumption and Carbon Dioxide Emissions in Central Asia, 1999

Country	Total Energy Consumption (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Electricity	Net Electricity Imports	Carbon Dioxide Emissions (Million metric tons of carbon)
Kazakhstan	1.46	29.5%	34.5%	29.9%	0.1%	4.0%	0%	2.1%	26.6

Kyrgyzstan	0.22	12.9%	31.1%	8.4%	0%	56.1%	0%	-8.5%	2.0
Tajikistan	0.26	21.6%	16.0%	0.9%	0%	60.7%	0%	0.8%	1.8
Turkmenistan	0.30	41.5%	68.9%	0%	0%	0.02%	0%	-10.4%	5.4
Uzbekistan	1.88	15.7%	76.8%	2.3%	0%	3.2%	0%	2.0%	27.7
Total/ weighted average	4.12	22.7%	55.0%	12.2%	0.04%	9.7%	0%	0.5%	63.5

Source: Energy Information Administration
Note: percentages may not add up to 100% due to rounding.

Table 3. Energy Supply Indicators, Central Asia

Country	Proven Crude Oil Reserves, 1/1/02E (Million Barrels)	Natural Gas Reserves, 1/1/02E (Trillion Cubic Feet)	Coal Reserves, 1/1/01E (Million Short Tons)	Petroleum Production, 2001E (Thousand Barrels Per Day)	Natural Gas Production, 2000 (Billion Cubic Feet)	Coal Production, 2000 (Million Short Tons)	Electric Generating Capacity, 2000 (Gigawatts)	Crude Oil Refining Capacity, 1/1/02E (Thousand Barrels Per Day)
Kazakhstan	5,417	65	37,479	811	314.3	82.4	17.3	427
Kyrgyzstan	40	0.2	895	2.1	0.5	0.8	3.8	10
Tajikistan	12	0.2	minimal	0.4	1.4	0.02	4.4	0.4
Turkmenistan	546	101	minimal	159	1,642	0	3.9	237
Uzbekistan	594	66.2	minimal	137	1,992	3.3	11.7	222
Total	6,609	232.6	38,374	1,109.5	3,950.2	86.52	41.1	896.4

Source: Energy Information Administration

Sources for this report include: AFX-Asia, Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring Central Asia Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, The Economist, The Financial Times, FSU Oil and Gas Monitor, Interfax News Agency, The International Herald Tribune, ITAR-TASS News Agency, The Moscow Times, Petroleum Economist, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, and World Markets Online.

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July 2002

Caspian Sea Region: Reserves and Pipelines Tables

Table 1. Caspian Sea Region Oil and Natural Gas Reserves

Country	Proven* Oil Reserves	Possible** Oil Reserves	Total Oil Reserves	Proven* Natural Gas Reserves	Possible** Natural Gas Reserves	Total Natural Gas Reserves
Azerbaijan	1.2 BBL	32 BBL	33.2 BBL	4.4 Tcf	35 Tcf	39.4 Tcf
Iran***	0.1 BBL	15 BBL	15.1 BBL	0 Tcf	11 Tcf	11 Tcf
Kazakhstan	5.4 BBL	92 BBL	97.4 BBL	65 Tcf	88 Tcf`	153 Tcf
Russia***	2.7 BBL	14 BBL	16.7 BBL	N/A	N/A	N/A
Turkmenistan	0.6 BBL	80 BBL	80.6 BBL	101 Tcf	159 Tcf	260 Tcf
Total	**10 BBL**	**233 BBL**	**243 BBL**	**170.4 Tcf**	**293 Tcf**	**463.4 Tcf**

Sources: Oil and Gas Journal, Energy Information Administration

* proven reserves are defined as oil and natural gas deposits that are considered 90% probable
** possible reserves are defined as oil and natural gas deposits that are considered 50% probable
*** only the regions near the Caspian are included

BBL = billion barrels, Tcf = trillion cubic feet

Table 2. Caspian Sea Region Oil Production and Exports

(thousand barrels per day)

Country	Production (1990)	Est. Production (2001)	Possible Production (2010)	Net Exports (1990)	Est. Net Exports (2001)	Possible Net Exports (2010)
Azerbaijan	259	311.2	1,200	77	175.2	1,000
Kazakhstan	602	811	2,000	109	631	1,700
Iran*	0	0	0	0	0	0

Russia**	144	11	300	0	7	300
Turkmenistan	125	159	200	69	107	150
Total	**1,130**	**1,292.2**	**3,700**	**255**	**920.2**	**3,150**

Source: Energy Information Administration

* only the regions near the Caspian are included
** includes Astrakhan, Dagestan, and the North Caucasus region bordering the Caspian Sea

Table 3. Caspian Sea Region Natural Gas Production and Exports

(billion cubic feet per year)

Country	Production (1990)	Est. Production (2000)	Possible Production (2010)	Net Exports (1990)	Est. Net Exports (2000)	Possible Net Exports (2010)
Azerbaijan	350	200	1,100	-272	0	500
Kazakhstan	251	314.3	1,100	-257	-176.6	350
Iran*	0	0	0	0	0	0
Russia**	219	30	N/A	N/A	N/A	N/A
Turkmenistan	3,100	1,642	3,900	2,539	1,381	3,300
Total	**3,920**	**2,072**	**6,100**	**2,010**	**1,204.4**	**4,150**

Source: Energy Information Administration

* only the regions near the Caspian are included
** includes Astrakhan, Dagestan, and the North Caucasus region bordering the Caspian Sea

Table 4. Oil Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Crude Capacity	Length	Estimated Cost/Investment	Status

Atyrau-Samara Pipeline	Atyrau (Kazakhstan) to Samara (Russia), linking to Russian pipeline system	Recently increased to 310,000 bbl/d	432 miles	Increase in capacity cost approximately $37.5 million	Existing pipeline recently upgraded by adding pumping and heating stations to increase capacity.
Baku-Ceyhan ("Main Export Pipeline")	Baku (Azerbaijan) via Tbilisi (Georgia) to Ceyhan (Turkey), terminating at the Ceyhan Mediterranean Sea port	Planned: 1 million bbl/d	Approximately 1,038 miles	$2.9 billion	One-year detailed engineering study completed in June 2002. Construction on Turkish section of pipeline began in June 2002. Completion of entire pipeline targeted for 2004, exports by Feb. 2005.
Baku-Supsa Pipeline (AIOC "Early Oil" Western Route)	Baku to Supsa (Georgia), terminating at Supsa Black Sea port	Recently upgraded from 115,000 to 145,000 bbl/d; proposed upgrades to between 300,000 bbl/d to 600,000 bbl/d	515 miles	$600 million	Exports began in April 1999; approximately 115,000 bbl/d exported via this route in 2001.
Baku-Novorossiisk Pipeline (Northern Route)	Baku via Chechnya (Russia) to Novorossiisk (Russia), terminating at Novorossiisk Black Sea oil terminal	100,000 bbl/d capacity; possible upgrade to 300,000 bbl/d	868 miles; 90 miles are in Chechnya	$600 million to upgrade to 300,000 bbl/d	Exports began late 1997; exports in 2001 averaged 50,000 bbl/d.

Baku-Novorossiisk Pipeline (Chechnya bypass, with link to Makhachkala)	Baku via Dagestan to Tikhoretsk (Russia) and terminating Novorossiisk Black Sea oil terminal	Currently: 120,000 bbl/d (rail and pipeline: 160,000 bbl/d); Planned: 360,000 bbl/d (by 2005)	204 miles	$140 million	Completed April 2000. Eleven-mile spur connects bypass with Russia's Caspian Sea port of Makhachkala.
Caspian Pipeline Consortium (CPC) Pipeline	Tengiz oil field (Kazakhstan) to Novorossiisk Black Sea oil terminal	Currently: 565,000-bbl/d; Planned: 1.34-million bbl/d (by 2015)	990 miles	$2.5 billion for Phase 1 capacity; $4.2 billion total when completed	First tanker loaded in Novorossiisk (10/01); exports rising to 400,000 bbl/d by end-2002
Central Asia Oil Pipeline	Kazakhstan via Turkmenistan and Afghanistan to Gwadar (Pakistan)	Proposed 1 million bbl/d	1,040 miles	$2.5 billion	Memorandum of Understanding signed by the countries; project stalled by regional instability and lack of financing.
Iran-Azerbaijan Pipeline	Baku to Tabriz (Iran)	Proposed 200,000 bbl/d to 400,000 bbl/d	N/A	$500 million	Proposed by TotalFinaElf.
Iran Oil Swap Pipeline	Neka (Iran) to Tehran (Iran)	175,000 bbl/d, rising to 370,000 bbl/d	208 miles	$400 million to $500 million	Under construction; oil will be delivered to Neka and swapped for an equivalent amount at the Iranian Persian Gulf coast.

Kazakhstan-China Pipeline	Aktyubinsk (Kazakhstan) to Xinjiang (China)	Proposed 400,000 bbl/d to 800,000 bbl/d	1,800 miles	$3 billion to $3.5 billion	Agreement 1997; feasibility study halted in September 1999 because Kazakhstan could not commit sufficient oil flows for the next 10 years.
Kazakhstan-Turkmenistan-Iran Pipeline	Kazakhstan via Turkmenistan to Kharg Island (Iran) on Persian Gulf	Proposed 1million bbl/d	930 miles	$1.2 billion	Feasibility study by TotalFinaElf; proposed completion date by 2005.
Khashuri-Batumi Pipeline	Dubendi (Azerbaijan) via Khashuri (Georgia) to Batumi	Initial 70,000 bbl/d, rising to 140,000 bbl/d-160,000 bbl/d	Rail system from Dubendi to Khashuri, then 105-mile pipeline from Khashuri to Batumi	$70 million for pipeline renovation	ChevronTexaco has canceled plans to rebuild and expand the existing pipeline.
Trans-Caspian (Kazakhstan Twin Pipelines)	Aqtau (western Kazakhstan, on Caspian coast) to Baku; could extend to Ceyhan	N/A	370 miles to Baku	$2 billion to $4 billion (if to Ceyhan)	Feasibility study agreement signed in December 1998 by Royal/Dutch Shell, ChevronTexaco, ExxonMobil, and Kazakhstan; project stalled by lack of Caspian Sea legal agreement.

Table 5. Natural Gas Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Capacity	Length	Estimated Cost/Investment	Status

Baku-Erzurum	Baku (Azerbaijan) via Tbilisi (Georgia) to Erzurum (Turkey), linking with Turkish natural gas pipeline system	Planned 254 Bcf capacity	540 miles	$1 billion (includes up to $500 million to construct new Azeri section)	Financing being arranged, construction originally scheduled to start in summer 2002.
"Centgas" (Central Asia Gas)	Daulatabad (Turkmenistan) via Herat (Afghanistan) to Multan (Pakistan). Could extend to India.	700 Bcf/year	870 miles to Multan (additional 400 miles to India)	$2 billion to Pakistan (additional $500 million to India)	Memorandum of Understanding signed by Turkmenistan, Pakistan, Afghanistan, and Uzbekistan. Presidents of Pakistan, Afghanistan, and Turkmenistan met in May 2002 to discuss reviving this pipeline idea.
Central Asia-Center Pipeline	Turkmenistan and Uzbekistan via Kazakhstan to Saratov (Russia), linking to Russian natural gas pipeline system	3.5 Tcf/year	Existing route	N/A	Operational. Turkmenistan is using this pipeline to export a total of 8.83 Tcf to Ukraine (via Russia) from 2002 to 2006, as well as smaller amounts to Russia.
China Gas Pipeline	Turkmenistan to Xinjiang (China). Could extend to Japan.	1 Tcf/year	4,1,61 miles; more if to Japan	$10 billion to China; more if to Japan	Preliminary feasibility study done by ExxonMobil, Mitsubishi, and CNPC
Trans-Caspian Gas Pipeline (TCGP)	Turkmenbashy (Turkmenistan) via Baku and Tbilisi to Erzurum, linking with Turkish natural gas pipeline system	565 Bcf in first stage, eventually rising to 1.1 Tcf/year	1,020 miles	$2 billion to $3 billion	Project stalled; negotiations between Turkmenistan and Azerbaijan over pipeline volumes restarted in October 2001.

Korpezhe-Kurt-Kui	Korpezhe (Turkmenistan) to Kurt-Kui (Iran)	283-350 Bcf/year; expansion proposed to 459 Bcf/year by 2005	124 miles	$190 million; 2005 expansion: $300 million to $400 million	Operational since December 1997.

Table 6. Bosporus Bypass Oil Export Routes
(for Oil Transiting the Black Sea)

Name/Location	Route	Crude Capacity	Length	Estimated Cost/Investment	Status
Adria-Druzhba Integration	Russian Druzhba export pipeline connected to Adria pipeline (flows reversed) to terminus at Omisalj (Croatia)	100,000 bbl/d in first full year of operation; increasing to 300,000 bbl/d	1,987 miles in total	$20 million to modernize Adria, integrate the pipelines, and reverse existing flows	Yukos expects exports from Omisalj via the integrated pipeline system to start by end-2002.
Albanian Macedonian Bulgarian Oil (AMBO) Pipeline	Burgas (Bulgaria) via Macedonia to Vlore (Albania) on Adriatic coast	750,000 bbl/d (could be expanded to 1-million bbl/d)	560 miles	$850 million to $1.1 billion	Construction delayed, (proposed 2001-2002) as financing is arranged. Completion originally targeted for 2004-2005.
Burgas Alexandropoulis (Trans-Balkan Oil Pipeline)	Burgas to Alexandropoulis (Greece) on the Aegean Sea coast	Proposed 600,000 bbl/d to 800,000 bbl/d	178 miles	$600 million	Initial agreement signed in 1997 between Bulgaria, Greece, and Russia. Project delayed.

Constanta-Trieste Pipeline	Constanta (Romania) via Hungary, Slovenia, and/or Croatia to Trieste (Italy) on the Adriatic Sea coast. Omisalj (Croatia) has also been proposed as a terminus.	660,000 bbl/d	855 miles	$900 million	Feasibility studies completed; financing still to be arranged.
South-East European Line (SEEL)	Constanta via Pancevo (Yugoslavia) and Omisalj to Trieste. Omisalj has also been proposed as a terminus.	660,000 bbl/d	750 miles	$800 million	Feasibility studies completed; financing still to be arranged.
Odesa-Brody Pipeline	Odesa (Ukraine) to Brody (Ukraine), linking to the southern Druzhba pipeline; optional spurs to the northern Druzhba line at Plotsk (Poland) and/or to Gdansk on the Baltic Sea coast.	500,000 bbl/d	400 miles from Odesa to Brody	$750 million for pipeline and Pivdenny terminal	Construction on pipeline completed in August 2001; Pivdenny terminal became operational in December 2001. Ukraine is seeking to sign contracts with Caspian oil exporters to fill the line.

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April 2002

Russia: Oil and Natural Gas Export Pipelines

OIL PIPELINES

Russia has an extensive domestic oil pipeline system, with links to nearly all of the former Soviet republics. Transneft, the state-owned transport monopoly, manages, services, and is responsible for developing Russia's pipeline system. Russia's main export pipeline to Europe is the 1.2-million-bbl/d-capacity *Druzhba* (Friendship) pipeline that traverses Belarus before splitting into northern and southern routes and delivering oil supplies to customers throughout Europe. The northern Druzhba line runs from Russia via Belarus to Poland and on to eastern Germany, while the southern Druzhba line cuts across northern Ukraine and on to Hungary, Slovakia, and the Czech Republic.

However, aside from the Druzhba pipeline and the Novorossiisk export terminal on the Black Sea, Russia's ability to export its oil to world markets is limited. With the breakup of the Soviet Union, Russia 's main export terminals for crude oil and oil products--in Ventspils (Latvia), Klaipeda (Lithuania), Tallinn (Estonia), and Odessa (Ukraine)--were located outside Russia's borders, forcing the country to pay transit fees to its neighbors in order to export its oil.

Since oil exports are a major source of revenue for Russia's budget, the country is seeking to increase its domestic export capacity and reduce the fees it pays to transit countries. Thus, Russia is building a number of new pipelines and export terminals, such as the Baltic Pipeline System, as well as increasing capacity at several existing terminals and pursuing plans to construct additional pipelines, including a potentially major oil export pipeline to China.

Baltic Pipeline System

Outside of the Caspian Sea region, the 284-mile Baltic Pipeline System (BPS) is Russia's largest new pipeline export scheme. This system involves the laying of a new main pipeline from Kharyaga (Nenets Autonomous District, Arkhangelsk region) to Usa (Komi Republic), the reconstruction of the Usa-Ukhta, Ukhta-Yaroslavl, and Yaroslavl-Kirishi pipeline segments, and the construction of a new pipeline from Kirishi to Primorsk and an oil terminal in Primorsk on the Gulf of Finland. The first stage of the BPS, with an export capacity of 240,000 bbl/d, was put into operation in December 2001 when the first tanker was loaded at Primorsk. The cost of the first stage of the BPS has been estimated at $460 million.

The BPS, which will export most of the oil from the Timan-Pechora and West Siberian oil provinces, as well as some oil from Kazakhstan, gives Russia a direct outlet to northern European markets, allowing the country to reduce its dependence on transit routes through Estonia, Latvia, and Lithuania. Use of the BPS, which is fully owned and operated by Transneft, the Russian pipeline monopoly, should bring the Russian government $100 million per year in fees, as well as allow Russia to save up to $1.5 billion each year in transit tariffs. In addition, Russian officials argue that the oil-loading terminal in Primorsk also allows Transneft to maneuver between southern and northern export routes, giving exporters greater flexibility and attracting more oil from the Caspian Sea region to transit Russia.

Transneft President Semyon Vainshtok announced in November 2001 that construction of the second stage of the BPS will begin in June 2002. The second stage of the BPS, which will take a year and a half to complete, will involve construction of three pump stations and eight storage tanks, as well as upgrades to the Yaroslavl-Kirishi pipeline. The cost of the second stage of construction, which will increase the capacity of the BPS to 360,000 bbl/d, is estimated at around $350 million to $400 million.

However, the BPS has already run into problems. In January 2002, Transneft pumped an average of 236,000 bbl/d through the BPS, nearing its capacity, but in February 2002, Finnish energy company Fortum, which purchased nearly one-third of the BPS exports in January, cut its orders by 85%. After ordering an average of 72,300 bbl/d for the month in January 2002, Fortum reduced its purchases from the BPS to an average of just 10,845 bbl/d in February, citing high levels of sulfur that entered the BPS in the Udmurtia and Bashkortostan republics, making it more expensive to process on delivery in Finland. Most of the oil that was pumped through the BPS in January 2002 came from came from Sibneft, Lukoil and Surgutneftegaz.

China Oil Pipeline

In order to supply China's increasing oil demand and boost its own export potential, Russia has been negotiating with China to build an oil pipeline linking the two countries. In July 2000, Russian President Vladimir Putin and Chinese President Jiang Zemin signed a memorandum of understanding on a feasibility study for a potential oil pipeline between Russia and China, and in September 2001, Russian and Chinese officials signed a general agreement to prepare a feasibility study for the construction of a Russia-China oil pipeline.

Originally, Transneft and Russia's second largest oil producer, Yukos, were working together on the idea of building the proposed $2.5-billion pipeline, which would bring East Siberian oil to northeastern China. Under a 25-year deal, the pipeline would supply China with 400,000 bbl/d starting in 2005--the equivalent of 26% of China's projected net imports then. Spur lines would eventually link the Talakanskoye, Verkhne-Chonskoye, and Yurubchenskoye fields to the main pipeline, boosting capacity to 600,000 bbl/d by 2010 and helping to alleviate localized fuel shortages in Russia that have been aggravated by high rail tariffs.

The preliminary proposal signed by Chinese and Russian sides called for the line to stretch 1,400 miles from Angarsk, across Mongolia, then into Beijing. Russia wants to cut the pipeline's distance by

traversing Mongolia, but China would like to circumvent Mongolia for security reasons. In addition, Yukos and Transneft have differed in their preferences for the pipeline route, with Yukos, which previously favored a pipeline route from its fields in the Tomsk region straight to China, now favoring a route that would terminate in Nakhodka on Russia's Pacific Ocean coast. Yukos argues that shipping crude via Nakhodka would give producers a bigger choice of buyers, while Transneft has said that both routes could eventually be built. Discussions on a final route for the pipeline are continuing.

Sakhalin Pipelines

Sakhalin Energy (Sakhalin-2), a consortium led by Royal Dutch/Shell (Netherlands/U.K.), has plans to build oil export pipelines to Japan, South Korea, and Taiwan by constructing nearly 480 miles each of oil and natural gas pipelines down the length of Sakhalin Island to the ice-free port of Prigorodnoye. The Sakhalin-2 energy project currently produces oil in the six months of the year when the bitterly cold seas off the island's eastern shores are free of ice. Sakhalin Energy's plan is expensive, but will allow year-round oil and natural gas exports.

The rival Sakhalin-1 group favors a shorter, 150-mile underwater pipeline. Sakhalin-1 partners propose to export their oil across the Tatar Straits to DeKastri, on the Russian mainland, where an existing tanker terminal could be expanded to handle exports to Asia. It will be much cheaper to build, but off-takers will have to contend with ice for several months a year. Capacity of both the terminal and pipeline is planned at 240,000-300,00 b/d. Sakhalin-1 says its export route will be cheaper than that of Sakhalin-2, and although Sakhalin-1 is attempting to speed up its timetable to start production in 2003 instead of 2005 as originally scheduled, Sakhalin-1 acknowledges that exports will not begin before 2005.

CPC Pipeline

In March 2001, the Caspian Pipeline Consortium's (CPC) Tengiz-Novorossiisk pipeline was commissioned. The CPC pipeline, which is run by an international consortium rather than Transneft, has an initial capacity of 564,000 bbl/d, with throughput eventually increasing to 1.34-million bbl/d in 2015. Oil from the Tengiz field in Kazakhstan began to flow via the 990-mile pipeline to Russia's Black Sea port of Novorossiisk, but flows were suspended several times because the CPC did not have an agreement with Russia's State Customs Committee to transit Russian territory. After Russia and Kazakhstan negotiated an oil transportation agreement and an "oil quality bank", the first tankers were loaded at Novorossiisk in October 2001.

With a 24% stake, the Russian government is the largest shareholder in the Caspian Pipeline Consortium, but the lack of a pipeline linking the CPC pipeline with Russia's Transneft pipeline system currently prevents Russian oil from flowing through the CPC pipeline. As a result, the ChevronTexaco-led Tengizchevroil consortium looks set to be the only bidder for pipeline space in 2002. Future inclusion of Russian crude will require Transneft to link its system to the CPC pipeline, as well as additional regulations or changes to the existing oil transit agreement and quality bank.

Druzhba-Adria Pipeline Integration

In October 2000, Yukos announced plans to integrate the Druzhba southern pipeline with the Adria

pipeline, which runs from the Adriatic port of Omisalj in Croatia to Hungary. Yukos signed a $20-million agreement with Croatian oil transport company Jadranski Naftovod to modernize the Adria pipeline to help integrate the two pipelines. By reversing the flows of the 110-mile pipeline between Omisalj and Sisak, the integration of the Druzhba and Adria pipelines will allow direct exports of Russian oil to the coast of the Adriatic Sea.

According to Yukos, Russian Urals blend crude oil should be flowing the 1,987-mile route to the deepwater Omisalj port by the end of 2002. In December 2001, the Ukrainian parliament ratified an agreement to reduce its tariff for Russian oil crossing its territory en route to Omisalj, a step that Russian oil companies had seen as the last major obstacle for the integration project to move forward. Ukraine's agreement to cut its transit tariff brought it in line with Belarus, Slovakia, Hungary, and Croatia, the other countries through which the route passes.

With the line reversed to Omisalj, Russian oil exporters will have direct access to the Mediterranean Sea, allowing them to bypass the Black Sea and the increasingly crowded Bosporus Straits. The entire Druzhba-Adria pipeline route would handle 100,000 bbl/d in 2003, the first full year of operation. Transneft and Jadranski Naftovod have said that exports via the pipeline would rise to 200,000 bbl/d after five years, and to 300,000 bbl/d after 10 years.

Sukhodolnaya-Rodionovskaya Pipeline

In September 2001, Transneft completed a 162-mile pipeline from Sukhodolny to Rodionovsky in the southern Rostov region, allowing oil headed south for the Russian Black Sea port of Novorossiisk to avoid transiting Ukraine. The 320,000-bbl/d line removes the need for Russian oil exporters to use a 60-mile stretch of pipeline in Ukraine. The original, Soviet-era pipeline sidetracked west into Ukraine to serve the Lisichansk refinery, but after the collapse of the Soviet Union, Ukraine began charging Transneft high transit fees to use the pipeline. Transneft decided it was worth the $240-million cost to construct a bypass pipeline in order to avoid Ukraine's high transit fees.

NATURAL GAS PIPELINES

Russia has a comprehensive domestic natural gas distribution system run by the state natural gas monopoly Gazprom, as well as a series of natural gas pipelines linking Russia to the former Soviet republics. Russia's main natural gas export pipelines to Europe run from West Siberia, across the Volga-Urals and Timan-Pechora, and through Ukraine and Belarus to Europe. The Brotherhood, Progress, and Soyuz gas pipelines, with capacities of 1 trillion cubic feet (Tcf) each, transit Ukraine, while the 1.0-Tcf Yamal-Europe pipeline crosses Belarus, and the 0.8-Tcf Northern Lights gas pipeline transits both Belarus and Ukraine.

With world natural gas demand increasing, Russia is attempting to increase its capacity to export its natural gas. In addition, with so many natural gas pipelines crossing Ukraine, Russia is seeking to build new pipelines to diversify its natural gas export routes. In order to reach lucrative markets in Western Europe and Asia, Russia is proceeding with the construction of a number of international natural gas pipeline projects, including the Blue Stream pipeline to Turkey, and possible pipelines from Russia's

Sakhalin Island to Asian markets.

"Blue Stream" Pipeline

In 1997, Russia and Turkey signed an intergovernmental agreement for the sale of 565 billion cubic feet (Bcf) per year of natural gas, beginning in 2001. To implement this agreement, the "Blue Stream Pipeline Company" was formed, and the countries agreed to build a pipeline directly from Russia to Turkey, via the Black Sea.

Construction on the 565-Bcf-per-year-capacity Blue Stream pipeline officially began in February 2000. The pipeline includes a 222-mile section in Russia, from Izobilnoye to Dzhugba on the Black Sea Coast, a 235-mile section on the bottom of the Black Sea that will connect Dzhugba to Samsun on the Turkish coast, and a further 300-mile link from Samsum to Turkey's capital at Ankara. The estimated cost of the pipeline, which is Russia's largest investment project, is between $3 billion and $3.3 billion. The seabed stretch of the pipeline, which will be laid at depths deeper than any other pipeline in the world, is estimated to cost $2 billion alone. ENI (Italy) and Gazprom each have a 50% stake in the Blue Stream project.

In the spring of 2001, investigations into allegations of corruption in Turkey in the tendering for the Blue Stream pipeline set the project back several months. Turkey's Energy Minister, Cumhur Ersumer, was forced to resign after being named in a court indictment of 15 ministry officials charged with corruption. Aside from setting back the timetable for completion of the project, the Blue Stream pipeline itself was unaffected, and in August 2001, the Saipem 7000, an Italian technological innovation that is the only ship in the world capable of laying pipelines at such depths, began laying the pipeline at the bottom of the Black Sea at a depth of nearly 7,000 feet.

In February 2002, the Saipem 7000 completed laying the first of two branches of the subsea section of the pipeline, with work on the second branch to be completed in May 2002. Construction of the Turkish onshore section of the pipeline is already complete, while the 222-mile Russian section of the pipeline, which includes compressor stations and underground storage facilities, is scheduled to be finished by September 2002.

Natural gas supplies through the Blue Stream pipeline are slated to being in the third quarter of 2002, with Russia scheduled to deliver 70.6 Bcf of natural gas to Turkey via the pipeline this year. From 2003 to 2009, Russia will increase deliveries via Blue Stream by 70.6 Bcf per year each year, with the pipeline reaching peak capacity of 565 Bcf per year in 2009. Over the course of the 25-year agreement, Russia will pipe 14.1 Tcf of natural gas to Turkey.

Ukraine Bypass and Yamal-Europe Pipelines

Gazprom currently supplies around 25% of European natural gas demand, and the company is eager to increase its penetration in the region. Approximately 90% of Russia's total natural gas exports to Europe are routed through Ukraine, which receives natural gas supplies as in-kind payment for allowing Russia's natural gas to transit its territory en route to European consumers (Ukraine purchases additional natural

gas from Russia to meet its domestic demand). The Yamal-Europe pipeline, which is routed through Belarus and Poland to Germany, is Russia's only natural gas export pipeline to Europe that is not routed through Ukraine.

Russia has questioned Ukraine's reliability as a transit country, noting Ukraine's $2-billion debt for natural gas supplies. Several times in the past few years, Russia has accused Ukraine of illegally taking more natural gas from than the amount for which it had contracted. With Russia's long-term energy supply agreement with the European Union, Russian officials have said that they need additional export routes to be able to meet Russia's increased supply obligations. As a result of the strained relations between Ukraine and Russia over natural gas transit, in October 2000 Gazprom officials proposed a new pipeline that would bypass Ukraine. However, Ukraine pledged to stop siphoning natural gas from the transit pipelines, and in October 2001, the two countries agreed on a 12-year debt restructuring deal for Ukraine's natural gas debts.

Gazprom has sent conflicting signals on its intentions with the second leg of the Yamal pipeline (stipulated in a 1993 Russia-Poland intergovernmental agreement) and the related question of a possible bypass route around Ukraine. In February 2002, Gazprom board member Boris Fyodorov told investors that the company's board of directors had decided to increase the capacity of the Yamal-Europe pipeline and drop the project to build the natural gas pipeline through Poland, bypassing Ukraine. Gazprom officials, however, denied reports that the company has scrapped plans for a north-south pipeline from Belarus to Slovakia via Poland, avoiding Ukraine.

Although there has been confusion as to what Gazprom's position is, what is clear is that the company is still interested in boosting Russia's natural gas export capacity to Europe by diversifying its export routes. Currently, the Yamal-Europe pipeline annually carries about 600 Bcf of Russian natural gas, which is sold to the Russian-German trading company Weih, and the pipeline is expected to handle about 1.17 Tcf of natural gas per year by 2003 after new compressor stations have been built in Poland. Gazprom's plans for a second stretch of the Yamal-Europe pipeline through Poland would increase capacity to 2.1 Tcf of natural gas per year, but Russia and Poland have differed on the route for the second leg, and Russia's shorter route would still cost an estimated $2 billion to construct. As a result, Yamal-Europe II appears to be on hold.

China Natural Gas Pipelines

Russia also is looking to eastern markets to export its natural gas to Asian countries. On September 29, 2000, Russia announced that it would expedite the development of eastern Siberia natural gas fields, as well as conduct a feasibility study for laying a natural gas pipeline to China in a bid to supply natural gas to China. Several international projects are seeking to deliver Russian natural gas to China, although China has narrowed it down to two major options: a BP (U.K.)-led consortium that is developing the Kovykta natural gas field, and the the Sakha consortium developing the Chayandinovskoye field. Analysts believe that only one pipeline will be needed.

The Chayandinovskoye option would cost approximately $6 billion-$10 billion and would entail a 1,700-

mile pipeline link from the Chayandinskoye field to Xinjiang region northern China. In March 2001, Russia's Sakhaneftegaz and China's National Oil & Gas Development Corp. signed a preliminary agreement to develop the Chayandinovskoye field, which is estimated to contain 43 Tcf of natural gas, and build a dedicated pipeline with capacity of between 423 Bcf and 706 Bcf per year. Gazprom may act as the operator for the pipeline.

The second option for China to receive Russian natural gas is via a pipeline linking Russia's Kovykta field in Irkutsk with northeastern China. The Kovykta field, which is being developed by Russia Petroleum, a BP-led consortium, has estimated natural gas reserves of 49 Tcf. The pipeline would terminate in South Korea via a sub-sea pipeline across the East China Sea. The most direct route for the proposed Irkutsk pipeline--which Russia Petroleum strongly prefers--would be to lay the pipeline through Mongolia into northern China and then down to South Korea.

However, China is urging that the pipeline bypass Mongolia and instead go around the eastern edge of that country and follow a route on to Manzhouli in northeastern China, then cross into North Korea before terminating in South Korea. China feels that a route across Mongolia would be geopolitically risky and argues that Mongolian natural gas demand does not justify having the pipeline cross its territory.

If China insists that the pipeline not traverse Mongolia, an extra 700 miles will be added to the 2,000-mile pipeline route. In addition to the political issues related to the pipeline crossing North Korea, the added cost (from the extra length) of the pipeline may make the extension to South Korea unfeasible. Thus far, Russia Petroleum has failed to agree on the price China will pay for the natural gas.

North TransGas Pipeline

In late April 2001, Gazprom signed an agreement with Finnish and German customers for a feasibility study on a pipeline that would carry Russian natural gas across the Baltic Sea to serve Scandinavia and Germany. The North TransGas pipeline, if it is built, will be well located to export natural gas production from the far north of European Russia and the Barents Sea, and also will allow Gazprom to avoid negotiating fees for transit countries. Gazprom's partners in the North TransGas pipeline project are Finland's Fortum and Germany's Wintershall and Ruhrgas. However, until Gazprom is restructured and attracts more foreign investment, it appears that only one of the proposed northern natural gas pipelines--Yamal-Europe II or the North TransGas pipeline--is possible due to Gazprom's financial woes.

Sakhalin-1 Natural Gas Pipeline to Japan

The Sakhalin-1 consortium, made up of ExxonMobil (U.S.), Rosneft, ONGC Videsh (India), and a consortium of Japanese firms, is developing the Odoptu, Chayvo and Arkutun-Dagi oil and natural gas fields on Sakhalin Island off Russia's Pacific Coast. The consortium is proposing to deliver natural gas from Sakhalin to Japan via a 120-mile pipeline linking its fields with Sapporo, on Japan's northernmost island of Hokkaido. A feasibility study for the pipeline, which could be extended to Tokyo, is scheduled to be completed in April 2002.

ExxonMobil, the project's operator, previously has stated that it believes the pipeline will be economically viable. ExxonMobil has already given the green light to increase investment at the fields, and the company has announced that Sakhalin-1 is planning to produce 335 Bcf of natural gas per year in 2003. Sakhalin-1 hopes to start piping natural gas to Japan in 2008, with exports reaching 360 Bcf per year.

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May 2002

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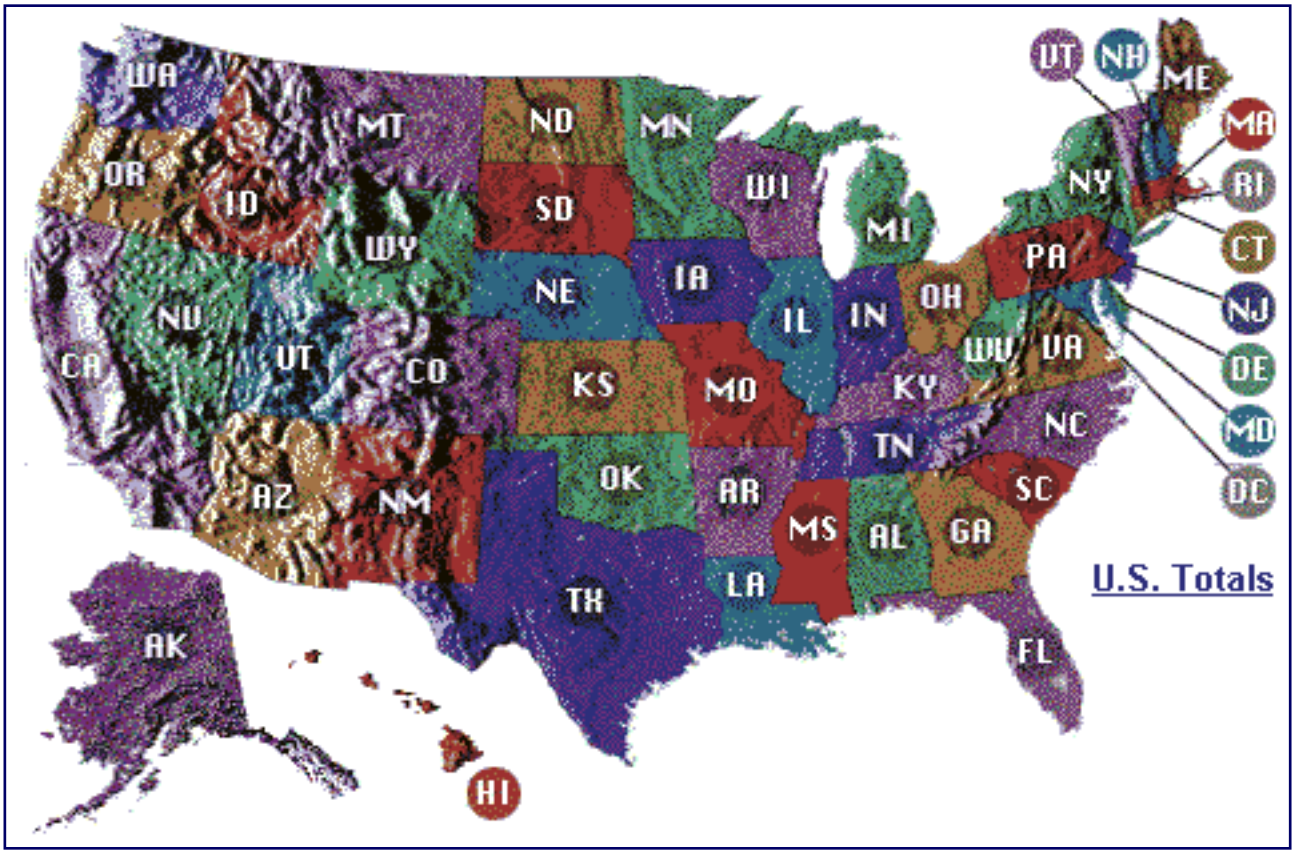
United States of America

The United States of America is the world's largest energy producer, consumer, and net importer. It also ranks twelfth worldwide in reserves of oil, sixth in natural gas, and first in coal.

Information contained in this report is the best available as of May 2002 and is subject to change. For the latest monthly U.S. outlook by the Energy Information Administration, please see the "Short-Term Energy Outlook".



GENERAL BACKGROUND

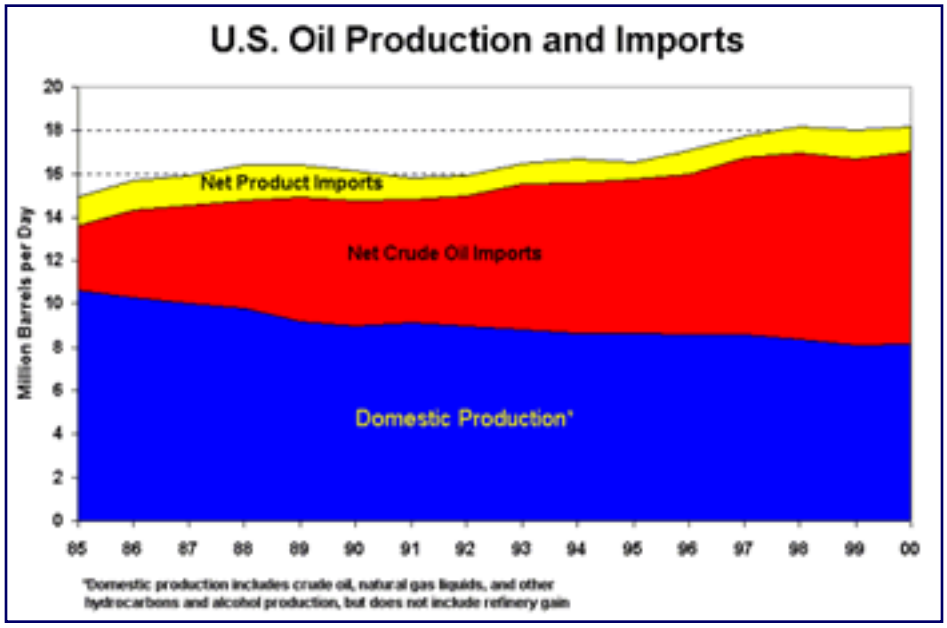
As of early May 2002, the U.S. economy appeared to be rebounding somewhat, following what may turn out to be one of the mildest recessions (or not a recession at all) in U.S. history. One possible factor which could harm the U.S. economic recovery is high oil prices. Also, in early May, the U.S. unemployment rate hit a seven-year high, moving up 0.3% to 6%. The recent difficulties experienced by the U.S. economy follow a period during the mid- and late-1990s of strong growth, low inflation, low unemployment, rapid productivity growth, and a booming stock market. Real (inflation adjusted) U.S. gross domestic product (GDP) growth for 2001 now is expected at 1.6%, up from 1.2% growth in 2001. Real GDP grew at a 5.8% rate in the first quarter of 2002, after growing by only 1.7% in the fourth quarter of 2001 and falling by 1.3% in the third quarter. Part of this recent growth appears to have been driven by businesses restocking inventories, and part by increased government spending. In addition, the US Federal Reserve moved aggressively to cut interest rates in response to the September 11, 2001 terrorist attack on the United States, and the U.S. Congress passed an economic stimulus package in March 2002.

For FY 2000, the federal budget ran a surplus of around $237 billion, higher than previously forecast. For 2001, the Congressional Budget Office (CBO) as late as spring was projecting a possibly even higher surplus for FY 2001. However, a combination of factors (economic slowdown, tax rebates) reduced this projected surplus significantly, with a deficit now considered likely in FY 2002. Meanwhile, the U.S. merchandise trade deficit surged to $427 billion in 2001. This deficit mainly reflected the strength of the U.S. economy (and a strong dollar) relative to major U.S. trading partners. The current account deficit now is running at over 4% of GDP, compared to 1.7% in 1997.

January 20, 2001, George W. Bush was inaugurated as President of the United States, succeeding Bill Clinton. In mid-May 2001, the Bush administration issued a series of energy policy recommendations as part of its new National Energy Policy Report, developed by a task force led by Vice President Dick Cheney. In August 2001, the U.S. House of Representatives passed an energy bill (the "Securing America's Future Energy" -- SAFE -- Act of 2001) which contained many of the energy plan's recommendations. In April 2002, the U.S. Senate passed its own version of an energy bill, which must now be reconciled with the House version.

OIL

The United States had 22.0 billion barrels of proved oil reserves as of January 1, 2002, twelfth highest in the world. These reserves are concentrated overwhelmingly (over 80%) in four states -- Texas (25% including the state's reserves in the Gulf of Mexico), Alaska (24%), California (21%), and Louisiana (14% including the state's reserves in the Gulf of Mexico). U.S. proven oil reserves have declined by around 20% since 1990, with the largest single-year decline (1.6 billion barrels) occurring in 1991.



During 2001, the United States produced around 8.1 million barrels per day (MMBD) of oil, of which 5.9 MMBD was crude oil, and the rest natural gas liquids and other liquids. U.S. total oil production in 2001 was down sharply (around 2.5 MMBD, or 24%) from the 10.6 MMBD averaged in 1985. U.S. crude oil production, which declined following the oil price collapse of late 1985/early 1986, leveled off in the mid-1990s, and began falling again following the sharp decline in oil prices of late 1997/early 1998. With the rebound in world oil prices since March 1999, U.S. crude production basically leveled off once again in 2000 and 2001. U.S. crude production for 2001 was the second lowest since 1950. In 2000, there were around 534,000 producing oil wells in the United States, the vast majority of which are considered "marginal" or "stripper" wells, generally producing only a few barrels per day of oil. For 2001, top oil producing areas included the Gulf of Mexico, Texas onshore, Alaska's North Slope, California, Louisiana, Oklahoma, and Wyoming.

Domestic oil exploration and development spending by U.S. major oil companies also rebounded during 2001 from the deep cuts made during the oil price collapse of 1997/1998. Improved technology and new or increased offshore production in the Gulf of Mexico (including at deepwater areas beyond the continental shelf) also could help matters. In 2000, deepwater production in the Gulf of Mexico for the first time surpassed shallow water production. In January 2000, Chevron and Shell -- the largest producer in the Gulf of Mexico -- signed an agreement to share drilling rigs and to drill exploratory wells jointly in the deep-water Gulf of Mexico. In March 2002, a US government lease sale for the central Gulf of Mexico produced bids totaling $363 million. Bidders included Dominion Exploration and

Production, Spinnaker Exploration, BP, Chevron, Kerr-McGee, BHP Petroleum, Nexen Petroleum Offshore USA, and Conoco. Overall, production from deepwater areas of the Gulf of Mexico has been increasing rapidly, with deepwater wells accounting for about two-thirds of total US Gulf output. Large fields include ExxonMobil's Hoover-Diana development (scheduled to start up this year), and BP's Atlantis, Crazy Horse (the largest single field every discovered in the Gulf of Mexico), Crosby, Holstein, King, King's Peak, Mad Dog, Marlin, and Nakika fields. BP has stated that it plans to accelerate its deepwater Gulf of Mexico production plans, possibly including construction of a $1-billion deep-sea pipeline, and to increase its production from 200,000 bbl/d currently to 750,000 bbl/d in 2007. This will require billions of dollars worth of investment.

Crude oil production in the lower 48 states is expected to remain essentially flat through 2002, as is Alaskan crude production, which accounts for around 17% of the U.S. total. Alaskan production is down about 50% from the 2.0 MMBD reached during the peak year of 1988. Most of Alaska's oil output comes from the giant Prudhoe Bay Field, and is transported via the Alyeska pipeline. A new oilfield, known as Alpine (owned 78% by Phillips Petroleum, 22% by Anadarko), began production in November 2000. Alpine represents the largest North American onshore oil discovery in a decade, and was producing 80,000 bbl/d of high quality, light crude oil by the end of 2000. Production at Alpine could rise to 120,000 bbl/d with tie-ins to the Nanuk and Fiord satellite fields. Phillips has been the largest oil producer in Alaska since acquiring Arco's Alaska fields in early 2000. In November 2000, two oil and natural gas lease sales conducted by the State of Alaska drew bids worth $11 million for offshore tracts in the Beaufort Sea and onshore in the North Slope. In another piece of news from Alaska, the critical Trans-Alaska Pipeline System (TAPS) shut down in early October after being punctured by a gunshot. The TAPS resumed operations on October 8, 2001.

In early 2000, the Energy Information Administration (EIA), in response to a Congressional request, issued a report on potential oil reserves and production from the Arctic National Wildlife Refuge (ANWR). The report, which cited a

1998 U.S. Geological Survey study of ANWR oil resources, projected that for the mean resource case (10.3 billion barrels technically recoverable), ANWR peak production rates could range from 1.0 to 1.35 MMBD, with initial ANWR production possibly beginning around 2010, and peak production 20-30 years after that.

According to Baker Hughes Inc., which has tallied weekly U.S. drilling activity since 1940, domestic oil and natural gas drilling has rebounded sharply since the low point of 488 reached in late April 1999 following the oil price collapse of late 1997. In mid-October 2001, for instance, the U.S. weekly "rig count" reached the 1,141 mark (933 for natural gas and 208 for oil), down slightly from earlier in the year but still close to the highest number since late 1990. Another interesting characteristic of the U.S. rig count is that natural gas rigs now outnumber oil rigs by more than three-fold. Historically, U.S. drilling activity peaked in 1981, with a total of 43,598 oil wells (and 20,166 natural gas wells) drilled in that year. For 2000, a total of 4,731 oil wells (and 15,206 natural gas wells) were drilled in the United States, up from 4,087 oil wells (and 10,513 natural gas wells) in 1999. Total natural gas wells drilled in 2000 were the most since 1984, prompted by record-high prices and surging natural gas demand.

Twenty-two major energy companies reported overall net income (excluding unusual items) of $4.6 billion on revenues during the fourth quarter of 2001 (Q401). This level of net income represented a 65% decrease relative to the fourth quarter of 2000 (Q400) (see EIA's "Performance Profiles for Major Energy Producers 2000"). Foreign upstream oil and natural gas production operations accounted for $2.0 billion of net income, followed by domestic upstream oil and natural gas production operations ($1.8 billion) and worldwide downstream natural gas and power operations ($1.5 billion). Besides the major energy companies, independent oil and natural gas producers, oil field companies and refiner/marketers also reported declines in net income (down 26%) during Q401 compared to Q400. As with the majors, this decline in net income was due to sharp drops during that period in the

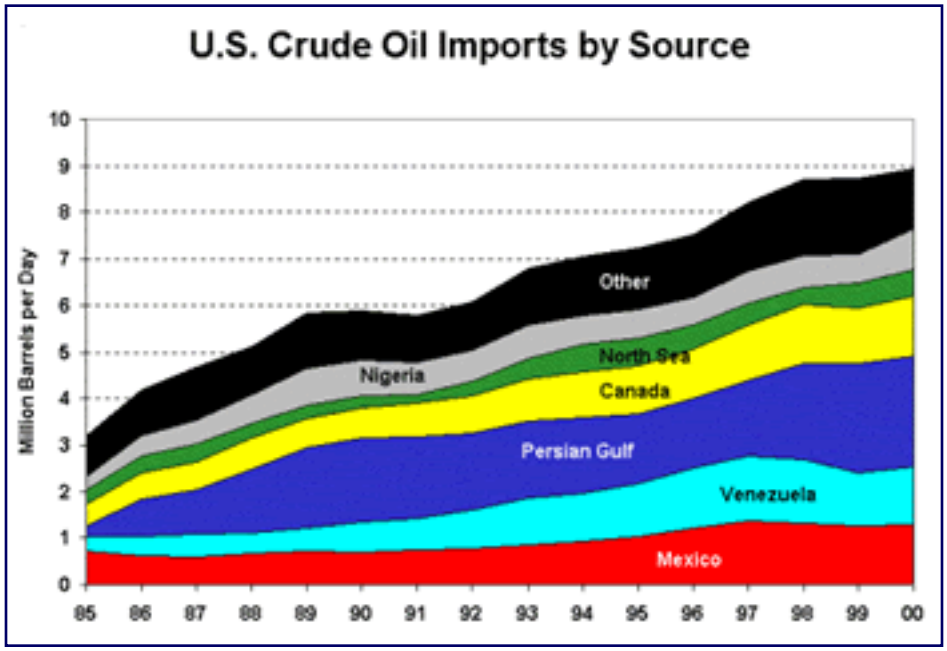
prices of oil and natural gas.

Consumption/Marketing

The United States consumed an average of 19.6 MMBD of oil in 2001. Of this, 8.6 MMBD (or 44% of the total) was motor gasoline, 4.7 MMBD (24%) "other oils," 4.0 MMBD (20%) distillate fuel oil, 1.7 MMBD (8%) jet fuel, and 0.8 million bbl/d (4%) residual fuel oil. U.S. oil demand is expected to remain roughly flat for 2002, and then begin increasing again in 2003. Following the September 11 terrorist attacks, U.S. jet fuel demand fell sharply. For the first three months of 2002, U.S. jet fuel consumption was down 11% compared to the same period in 2001.

Imports/Exports

The United States had *total gross oil* (crude and products) imports of an estimated 11.6 MMBD during 2001, representing around 59% of total U.S. oil demand. Around 47% of this oil came from OPEC nations, with Persian Gulf sources accounting for about 23% of U.S. oil imports during the year. Overall, the top suppliers of oil to the United States during 2001 were Canada (1.8 MMBD), Saudi Arabia (1.7 MMBD), Venezuela (1.5 MMBD), and Mexico (1.4 MMBD). During 2001, about 48% of U.S. *gross crude oil* imports came from the Western Hemisphere (19% from South America, 15% from Mexico, 14% from Canada), while 30% came from the Persian Gulf region (18% from Saudi Arabia, 9% from Iraq, 3% from Kuwait).



U.S. Energy Sanctions Issues

The United States maintains energy sanctions against several countries, including Iran, Iraq, and Libya (an oil embargo against Serbia was lifted by President Clinton on October 12, 2000). Iraq remains under comprehensive sanctions imposed after its invasion of Kuwait in August 1990. Iran and Libya are affected by the Iran-Libya Sanctions Act (ILSA), passed unanimously by the U.S. Congress and signed into law by President Clinton in August 1996. ILSA imposes mandatory and discretionary sanctions on non-U.S. companies which invest more than $20 million annually (lowered in August 1997 from $40 million) in the Iranian oil and natural gas sectors. The passage of ILSA was not the first U.S. sanction against Iran. In early 1995, President Clinton signed two Executive Orders which prohibited U.S. companies and their foreign subsidiaries from conducting business with Iran. The Orders also banned any "contract for the financing of the development of petroleum resources located in Iran." On March 13, 2001, President Bush, citing threats posed by Iran to U.S. national security, extended Clinton's two Executive Orders on Iran for another 6 months. On August 3, 2001, President Bush signed into law the ILSA Extension Act of 2001. This Act provides for a 5-year extension of ILSA with amendments that affect certain of the investment provisions.

Attempts by the United States to implement ILSA have run into opposition from a number of foreign governments. The European Union (EU) opposes the enforcement of ILSA sanctions on its members, and on November 22, 1996 passed resolution 2271 directing EU members to not comply with ILSA. On May 18, 1998, the EU and the U.S. reached an agreement on a package of

measures to resolve the ILSA dispute at the EU/U.S. Summit in London, but the Summit deal is contingent upon acceptance by the U.S. Congress before full implementation may take place.

On April 5, 1999, following the Libyan handover of two suspects in the 1988 bombing of Pan Am flight 103 to stand trial before a Scottish Court in the Netherlands, the United States modified its Libya sanctions on April 28, 1999 to allow shipments of donated clothing, food and medicine for humanitarian reasons (trade in informational materials such as books and movies is also allowed). However, all other U.S. sanctions against Libya remain in force. On February 1, 2001, one suspect was convicted by the Scottish court, while another was acquitted. The U.S. and British governments both said that they still expected Libya to accept responsibility for the murders, which Libya has said it would not do.

Refining

The United States has experienced a steep decline in refining capacity since 1981. Between 1981 and 1989, the number of U.S. refineries fell from 324 to 204, representing a loss of 3 MMBD in operable capacity, and a concomitant increase in refining capacity utilization from 69 to 86%. Much of this decline resulted from the 1981 deregulation (elimination of price controls and allocations), which effectively removed the major prop from underneath many marginally profitable, often smaller, refineries. Between 1989 and 1992, refining capacity remained roughly stable. Since 1992, over 30 additional, mainly small U.S. refineries have shut down, for a wide variety of reasons (economic, regulatory, etc.). This, combined with higher refinery runs, raised average weekly capacity utilization to 96% in 1998, before falling off to an average 92.7% in 1999. As of October 2001, capacity utilization at U.S. refineries reportedly was averaging around 92%-94%. Although financial, environmental, and legal considerations make it unlikely that new refineries will be built in the United States, expansion at existing refineries likely will increase total U.S. refining capacity in the long-run. EIA reports that nameplate refining capacity has increased by about 700,000 bbl/d between

1997 and 1999.

Since the mid-1980s, several U.S. refiners have joined with foreign (especially Venezuelan) companies in various joint venture arrangements. In 1986, for instance, Venezuela's state oil company PdVSA acquired a 50% interest in Citgo's U.S. refining operation. In 1988, Texaco and Saudi Aramco created Star Enterprise, an integrated refining and marketing operation with three refineries and a network of Texaco gasoline stations. Unocal and PdVSA followed suit in 1989, forming Uno-Ven Co. (in 1997, PdVSA bought out Unocal's share). In late October 1997, Mobil signed an agreement with a PdVSA subsidiary on joint ownership of the 170,000-bbl/d refinery in Chalmette, Louisiana.

Strategic Petroleum Reserve (SPR)

The SPR was officially established on December 22, 1975, when then-President Ford signed the Energy Policy and Conservation Act (EPCA). EPCA declared it to be U.S. policy to establish a petroleum reserve of up to 1 billion barrels. In order to store the reserve oil, the U.S. government in April 1977 acquired several salt caverns along the Gulf of Mexico coastline. The first crude oil was delivered to the SPR on July 21, 1977, and stored at the West Hackberry storage site near Lake Charles, LA. Other major storage sites include: Bryan Mound and Big Hill in Texas; and Bayou Choctaw, the St. James Terminal in Louisiana, with a total storage capacity of 700 million barrels.

The volume of oil stored in the SPR peaked at 592 million barrels in 1994. After selling off $327 million worth of SPR oil in 1996, and $220 million in 1997, the SPR contained around 566 million barrels of oil as of May 1 -- still the largest emergency oil stockpile in the world. However, in relative terms the SPR has shrunk from about 115 days of import replacement in 1985 to around 51 days now. In mid-November 2001, President Bush directed the Department of Energy (DOE) to fill the SPR to its capacity of 700 million barrels in order to "maximize long-term protection against oil supply disruptions." Under the DOE plan, the SPR is to be filled with "royalty in

kind" (RIK) oil.

Under EPCA, there is no preset "trigger" for withdrawing oil from the SPR. Instead, the President determines that drawdown is required by "a severe energy supply interruption or by obligations of the United States" under the International Energy Agency. EPCA defines a "severe energy supply interruption" as one which: 1) "is, or is likely to be, of significant scope and duration, and of an emergency nature;" 2) "may cause major adverse impact on national safety or the national economy" (including an oil price spike); and 3) "results, or is likely to result, from an interruption in the supply of imported petroleum products, or from sabotage or an act of God."

Should the President decide to order an emergency drawdown of the SPR, oil would be distributed mainly by competitive sale to the highest bidder(s). This would be accomplished in a 4-step process, including a "Notice of Sale," receipt of bids, selection of bidders, and finally delivery of oil. Today, the SPR can withdraw oil at a maximum sustained rate of 4.1-4.2 MMBD for a 90-day period (lower after that).

On September 22, 2000, President Clinton authorized the release of 30 million barrels of oil from the SPR over 30 days in an attempt to bolster U.S. oil supplies and to alleviate possible shortages of heating oil during the upcoming winter. The release took the form of a "swap" (bidding results were announced on October 4) in which crude oil volumes drawn from the SPR is to be replaced by the recipients at a later date. Oil prices fell in anticipation of, and in reaction to, the news.

Oil Mergers and Acquisitions

Pushed in part by low oil prices during 1998 and into early 1999, but also by the desire for oil reserves, cost cutting, and higher refining/marketing shares, merger activity in the oil business accelerated sharply over the past 2-3 years. The largest merger/acquisition announcements came from BP and Amoco, Exxon and Mobil, BP Amoco and ARCO, and, most recently, Chevron and Texaco. BP and Amoco completed their $53-billion merger on December 31,

1998, a day after the deal received regulatory approval from the U.S. Federal Trade Commission (FTC), subject to certain conditions.

On April 13, 2000, the FTC approved the $27.6-billion BP Amoco-ARCO deal. This followed the March 15, 2000 announcement by Phillips Petroleum that it had agreed to purchase ARCO's assets in Alaska for $6.5 billion. The sale was made as part of an effort to secure approval from the FTC. On the same day, the FTC announced that it had suspended its antitrust lawsuit seeking to block the merger, citing progress in talks with the companies involved. Among other issues, the FTC was concerned that the BP Amoco-ARCO merger would control about 75% of Alaskan North Slope crude oil output and over 70% of the critically important TAPS line, potentially hurting consumers on the U.S. west coast. BP Amoco agreed to sell some pipeline and oil storage holdings in Cushing, Oklahoma. The new company (now called BP) will rank in the top three private oil companies in the world, along with ExxonMobil and Royal Dutch/Shell.

Meanwhile, the $81-billion merger between Exxon and Mobil, which formed the world's largest privately owned petroleum company (in terms of revenues), was approved by the FTC on December 1, 1999, subject to the divestiture of 2,400 service stations and other assets (on December 3, 1999, 1,740 of these stations were sold to Tosco, the largest U.S. independent oil refiner). In a related development, in April 2000, Duke Energy said that it had agreed to acquire Mobil's European natural gas trading and marketing business. The sale of Mobil's natural gas operations in Europe was required by the European Commission as part of its approval of the ExxonMobil merger.

On October 16, 2000, another major oil industry merger/acquisition was announced, this time between Chevron and Texaco. According to the announcement, Chevron is to buy Texaco for $35 billion in stock, creating the world's fourth largest energy company (behind ExxonMobil, Shell, and BP).

The deal received regulatory approval in early October 2001, and was approved by shareholders of the two companies on October 9, creating ChevronTexaco.

On November 3, 2000, Russia's Lukoil announced that it intended to purchase Getty Petroleum Marketing for $71 million. Lukoil eventually intends to switch Getty's 1,300 retail outlets in the Northeastern and Middle Atlantic states to the Lukoil brand name. The purchase represents the first takeover of a publicly traded U.S. company by a Russian firm. In late January 2001, Getty shareholders approved the the buyout.

On November 19, 2001, the *Wall Street Journal* reported that Phillips Petroleum and Conoco Inc. agreed to merge in a $15.2 billion transaction. This transaction would create a company (to be called ConocoPhillips) that will be the sixth-largest oil and gas company in the world, the largest U.S. refiner, and the third-largest U.S.-based energy company.

On March 26, 2002, *The Wall Street Journal* reported that Shell Oil Co. agreed to acquire Pennzoil-Quaker State Co. for $1.8 billion and to assume $1.1 billion of Pennzoil-Quaker State debt. *The Wall Street Journal* noted that this transaction combines Shell's 3% share of the U.S. market for passenger car motor oil with Pennzoil-Quaker State's 35% share. Shell also adds Pennzoil-Quaker State's 46,200 barrels-per-day Shreveport, Louisiana refinery and more than 2,000 Jiffy Lube outlets.

Besides these large mergers, several defensive mergers among smaller, independent oil companies also have been unveiled recently, including Kerr-McGee Corp.'s (KMG) $1.86-billion takeover of Oryx Energy Co. (ORX), and an agreement between Seagull Energy Corp. (SGO) and Ocean Energy Inc. (OEI) to merge in a $1.1-billion deal. On July 14, 2000, Anadarko Petroleum announced the closing of its merger transaction with the Union Pacific Resources Group. Union Pacific became a wholly owned subsidiary of Anadarko, creating one of the largest U.S. independent oil and natural gas companies. In January 2001, Amerada Hess announced that it was

withdrawing a $3.5-billion offer to purchase Britain's Lasmo P.L.C., a move which would have created a "super-independent" oil company. Instead, Lasmo was purchased by Italy's ENI for $4 billion.

Due to low profitability in the refining/marketing line of business, U.S. integrated major energy companies began a process during the 1990s of selective refining/marketing divestiture, and numerous U.S. refineries were shut down. Among independent refiners, growth largely has been concentrated in the following group of companies: Citgo/PDV America, Clark Refining and Marketing, Diamond Shamrock (merged with Ultramar during 1996, creating Ultramar Diamond Shamrock), Koch Industries, Tesoro Petroleum, Ultramar, and Valero Energy. In May 2001, Valero agreed to acquire Ultramar Diamond Shamrock for $6 billion. Another company, Tosco Corporation, was purchased by Phillips Petroleum for $7.5 billion in September 2001, creating the second largest refining group in the United States, behind ExxonMobil.

NATURAL GAS

As of January 1, 2002, the United States had estimated proven natural gas reserves of 177 trillion cubic feet (Tcf), or 3.2% of world reserves (6th in the world). In 2001, the United States produced 19.1 Tcf of dry natural gas. Also during 2001, the United States consumed 22.7 Tcf and imported (net) around 3.5 Tcf of natural gas, mainly from Canada. Overall, the United States depends on natural gas for about 23% of its total primary energy requirements (oil accounts for around 39% and coal for 23%).

Natural gas wellhead prices reaching record highs of nearly $10.00 per thousand cubic feet (mcf) in late 2000/early 2001, but fell sharply soon thereafter to around $2.50 per mcf. Natural gas spot prices have been hovering over $3.00 per thousand cubic feet since March 2002. This may be explained in part by 1) the unusual weather patterns in March and April: March and much of April were colder than normal, but in part of April, an unusual and intense heat wave occurred, resulting in a surge in electricity

demand for cooling, which in turn led to increased demand for natural gas in the power sector; 2) the rising price of crude oil due to a general concern in the market in response to the current tensions in the Middle East; 3) the sense that the U.S. economy is recovering at a more rapid pace than previously expected; 4) the increased capacity and the planned new capacity of gas-burning power plants; and 5) concerns that natural gas production, as well as drilling and exploration, have recently fallen off, resulting in a less rosy supply outlook for the near term. For 2002, assuming normal weather and barring any major supply disruptions, the annual average natural gas wellhead price is projected to be about $2.80 per mcf compared to over $4.00 per mcf last year.

Natural Gas Production

Domestic natural gas production is projected to increase through 2002 as the effects of sharply increased drilling over the past year begin to be felt. Exploration and production budgets for many natural gas producers increased sharply in 2000, spurred by higher prices and greatly improved current and expected revenues.

U.S. natural gas production (and net imports, mainly from Canada) is likely to increase sharply over the next two decades in response to strong demand, abundant reserves, and improved unconventional and offshore recovery technology. Increased natural gas production is expected to come mainly from onshore sources, although offshore Gulf of Mexico production also is forecast to grow significantly. In August 2001, for instance, ExxonMobil began production at its $330 million Mica natural gas project in the deepwater Gulf of Mexico. Alaska's North Slope fields also represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas reserves. Alaska's Governor Tony Knowles has stated that he supports a $17.2 billion natural gas pipeline running from the North Slope along the Alaska Highway into Alberta and on to markets in the U.S. Midwest (another option would be to route the pipeline via the MacKenzie Delta in northern Canada). Increased natural gas production likely will come mainly from lower 48 sources, with increased use of cost-saving technologies expected to result in continuing

large natural gas finds, including in the deep waters of the Gulf of Mexico but also in conventional onshore fields. Currently, top natural-gas-producing states (in descending order) include Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Colorado, Kansas, Alaska, California, and Alabama.

Natural Gas Demand

From 1990 through 2001, natural gas consumption in the United States increased by about 14%, and this growth is likely to continue in the future. Greater use of natural gas as an industrial and electricity generating fuel can be attributed, in part, to its relatively clean-burning qualities in comparison with other fossil fuels. Lower costs resulting from greater competition and deregulation in the natural gas industry and an expanding transmission and distribution network have also helped expand its acceptance and use. In 2001, natural gas consumption fell by over 1.1 Tcf, after a 0.9 Tcf increase in 2000. During 2001, natural gas consumption by electric utilities fell sharply, to 2,675 billion cubic feet (Bcf), down 368 Bcf from 2000. Natural gas is consumed in the United States mainly in the industrial (42%), residential (22%), commercial (15%), and electric utility (13%) sectors (note: EIA generally places consumption of natural gas for power generation by nonutilities, including natural gas used for industrial cogeneration, in the "industrial" category). For the first three months of 2002, natural gas demand is down 5% from the same period the previous year.

U.S. natural gas consumption and imports, largely from Canada (and to a far lesser extent from liquefied natural gas -- LNG, with Mexico a small net importer of natural gas from the United States), are expected to expand substantially in coming decades, with the fastest volumetric growth resulting from additional natural-gas-fired electric power plants. In particular, new combined-cycle facilities furnished with more efficient natural gas turbines will help lower the cost of natural-gas-generated electricity to levels competitive with coal-fired plants. Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure -- $1.5 trillion over the next 15 years according to the National Petroleum Council. The largest natural gas pipeline project currently under

construction is the $1.2 billion Gulf Stream pipeline, which will run 564 miles from Alabama to Florida. Mexico could potentially become a significant natural gas exporter to the United States in the long term. One U.S.-Mexican natural gas pipeline proposal currently on the table is the $230-million, 212-mile North Baja line connecting southeastern California and Tijuana, Mexico. Companies involved in this project include Sempra Energy, PG&E, and Mexico's Proxima Gas. The project is slated to come online in January 2003, but is currently awaiting approval by the U.S. Federal Energy Regulatory Commission (FERC).

Domestic and Import Pipelines

On November 1, 1993, FERC issued Order No. 636, which decoupled the various stages of the natural gas industry between wellhead and end-user. This order has led to significant restructuring of the interstate natural gas pipeline industry, including moves towards unbundled services, diversification into other energy sectors, and development of mega-pipeline systems.

During the past decade, interstate natural gas pipeline capacity has increased substantially. From January 1996 through August 1998 alone, at least 78 projects were completed adding approximately 11.7 billion cubic feet per day of capacity, and much more will be needed in coming years. Recently completed pipelines include the Pony Express project and the Trailblazer system expansion, providing access from the Wyoming and Montana production regions. Also, the Transwestern and El Paso natural gas pipeline expansions have increased capacity from New Mexico's San Juan Basin.

On December 1, 2000, the $2.9-billion, 1.3-Bcf/day Alliance Pipeline from western Canada (Fort St. John, British Columbia) to the Chicago area entered service. Another pipeline, the Independence Pipeline ($678 million), has been delayed until November 2002, but received FERC approval in July 2000. Columbia Gas System’s Millennium project ($700 million), which would connect Canadian natural gas sources to New York and Pennsylvania, remains in the regulatory approval process. In February 2000, FERC issued

Order 637, the goal of which is to build on Order 636 and to further deregulate the U.S. natural gas industry. The order calls for price liberalization for short-term resale of pipeline capacity and allowance of seasonal rate differentials.

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. The U.S. and Canadian natural gas grids are highly interconnected and Canadian natural gas has become an increasingly important component of the total natural gas supply for the United States. This is especially true for certain U.S. regions such as the Northeast, Midwest, and Pacific, which depend on Canadian natural gas for significant amounts of their supply. Overall, the United States received about 3.8 Tcf of natural gas (net) from Canada in 2001. Mexico is a small net importer of natural gas from the United States.

The most significant recent expansion of natural gas pipeline capacity from western Canada to the United States is the Northern Border system through Montana into the Midwest. Expansion of the TransCanada pipeline will add another 164 Bcf to these imports, while the new Alliance pipeline from western Canada to Chicago will add as much as 730 Bcf (although not immediately; for a while there will be spare pipeline capacity as production capacity ramps up). This trend is expected to continue as Canadian production expands rapidly in the western provinces of British Columbia and Alberta and is developed off the east coast of Nova Scotia. Consequently, more pipeline projects are expected to be built to gain greater access to these Canadian supplies, including proposed expansion of the NOVA system in Alberta, Canada, by up to 2.3 Bcf per day. This in turn will link with the TransCanada Pipeline system expansion and its connections with existing and new U.S. pipelines feeding into the expanding markets in the Midwest and Northeast. In addition, the Maritimes & Northeast Pipeline running from Sable Island to New England, began operations in early 2000.

On October 12, 2001, the U.S. Coast Guard lifted the ban on liquefied natural gas (LNG) tankers from Boston harbor. The ban, in effect since September 26

(two weeks after the terrorist attacks in New York and Washington, DC), was established in response to security and safety concerns about the ships that bring LNG to the import facility of Distrigas of Massachusetts (a Division of Tractebel, Inc.). The decision enabled the reopening of the Distrigas facility in Everett, Massachusetts, which received 45 shipments containing 99 Bcf of natural gas in 2000, mostly from Trinidad, accounting for 44% of total LNG imports into the United States that year. LNG is an integral part of natural gas supplies for New England. This is particularly true during the winter season, when LNG represents around 30% of local distribution company (LDC) deliveries to consumers. The Distrigas facility is one of three currently active LNG facilities in the United States. The other two active facilities are located in Lake Charles, Louisiana, and the recently reopened facility in Elba Island, Georgia. An additional LNG facility, in Cove Point, Maryland, is scheduled to reopen in 2002. There is growing interest in LNG to supply natural gas for electric power generation and provide supply flexibility. EIA expects that LNG imports to the United States will increase at an average 8.6% annual rate to 830 Bcf by 2020.

Natural Gas Mergers, Acquisitions, Bankruptcies

As with oil, a number of major natural gas market participants are engaging in various forms of corporate combinations, such as mergers, acquisitions, and strategic alliances. The value of mergers and acquisitions within the natural gas industry quadrupled from $10.4 billion in 1990 to $39 billion in 1997. This increase parallels an enormous surge in corporate combinations (mergers, acquisitions, joint ventures and strategic alliances) across the energy sector. In August 2001, Devon Energy announced the acquisition of Mitchell Energy for $3.1 billion, forming the second largest independent natural gas producing company in the United States, behind Anadarko Petroleum Corp. In late January 2001, El Paso Energy completed its $24-billion merger with Coastal, creating the fourth-largest U.S. energy company by market capitalization (after BP, Texaco-Chevron, and Enron). The October 1999 merger between El Paso Energy Corporation and Sonat had created the largest transporter of natural gas in the country.

On December 2, 2001, Enron, formerly the world's largest electricity and natural gas trading company, filed for Chapter 11 bankruptcy in the Southern District of New York for 14 affiliated entities, including Enron, Enron North America, Enron Energy Services, Enron Transportation Services, Enron Broadband Services, and Enron Metals & Commodity Corporation. Enron had been the seventh-largest publicly-traded energy company in the world. Also in early December 2001, Enron filed a $10 billion lawsuit against Dynegy, alleging breach of contract, in connection with Dynegy's November 28 termination of its proposed merger with Enron. On November 9, 2001, Enron had agreed to an all-stock takeover by former competitor Dynegy. ChevronTexaco, a 27% stakeholder in Dynegy, was to inject $1.5 billion of cash immediately into Enron, and an additional $1 billion into the combined entity. The merged company was to be called Dynegy Inc., and Dynegy executives were to occupy all top positions. On November 28, 2001, however, Dynegy withdrew from the merger deal.

On January 2, 2002, the U.S. Department of Justice confirmed that a criminal probe of Enron has been launched. A task force was formed to investigate whether the former giant energy company defrauded investors by deliberately withholding or falsifying crucial financial information. The U.S. Securities and Exchange Commission has been investigating Enron since October 2001. A number of civil suits already have been filed against Enron.

COAL

The United States produced 1,121 million short tons (Mmst) of coal in 2001, consumed 1,081 Mmst and exported (net) 49 Mmst. Wyoming is by far the leading U.S. coal-producing state (with 33% of the U.S. total), followed by West Virginia (14%) and Kentucky (12%). Appalachia accounted for 38% of total U.S. production in 2001, mainly from underground mines. Nearly all remaining U.S. coal production came from states west of the Mississippi River, overwhelmingly from surface mines. Around three-fifths of U.S. coal production is bituminous, one-third subbituminous, and about one-tenth lignite (brown coal). Around 80,000 miners work in the $20 billion U.S. coal industry, down from a peak of 700,000 in 1923, when U.S. coal

production was half what it is today. Major U.S. coal companies include Peabody Energy (the largest in terms of production), Arch Coal (the second largest coal producer); and Kennecott Energy.

During 2001, coal production increased in all regions of the United States, particularly the West. Low-sulfur western coal production surpassed relatively higher-cost, higher-sulfur, Appalachian coal for the first time in 1998, following strong increases since 1994, prompted largely by Phase 1 of the Clean Air Act Amendments of 1990 (CAAA). CAAA originally took effect during 1995, and required lower sulfur emissions from coal combustion. In response, Wyoming increased its coal production sharply, particularly low-sulfur, low-ash (and low cost) coal from the Powder River Basin, where coal is strip-mined. Output growth from Appalachia in 1996 was largely a result of strong demand by eastern electric utilities, a decline in nuclear and natural-gas-fired generation in the East, and a rise in exports. A proposal to ship Western coal to power plants in the eastern and midwestern United States via a new, $1.4 billion rail line currently is under consideration by Federal regulators.

The electric power sector (utilities and nonutilities) accounts for the vast majority (around 90%) of U.S. coal consumption, with independent power producers (IPPs) and manufacturing taking nearly all the rest. This pattern is expected to continue through 2020 at least, with coal maintaining a fuel cost advantage over oil and natural gas, and coal demand reaching 1,365 Mmst. As sulfur dioxide emissions standards are tightened (in 2000, for instance, Phase 2 of CAAA took effect), the share of low-sulfur coal in the U.S. coal consumption mix is expected to increase. In 1999, low and medium-sulfur coals had approximately the same share of the U.S. coal market, with high-sulfur coal far behind.

U.S. coal exports have fallen precipitously since 1995 due mainly to lower world coal prices and increased competition from other coal-producing nations (i.e., Australia, South Africa, China, Venezuela, Colombia), plus natural gas -- especially in Europe. In 2001, total U.S. coal exports

dropped to the lowest level since 1978, largely due to 1) a strong U.S. dollar, which gave an edge to other coal-exporting countries; and 2) the tight supply market in the United States, which resulted in increased spot prices of coal, influencing some producers to shift their output to the domestic market. Metallurgical coal exports experienced the greatest decline in 2001, accounting for 75% of the total decline. Export markets for metallurgical coal have been declining over the past few years because of the expansion of new steel-making technologies requiring less high-grade coking coal. Consequently many U.S. metallurgical coal operations have closed, and increased amounts of metallurgical coal have been sold into the domestic utility steam coal market. The U.S. coal industry is expected to continue to face strong competition from other coal-exporting countries, with limited or negative growth in import demand in Europe and the Americas. Given this, it is likely that the U.S. share of world coal exports will decline in coming years.

Meanwhile, U.S. coal imports, although still representing an extremely small part of total U.S. coal consumption (less than 2%), increased dramatically in 2001. Total coal imports were 19.8 million short tons, an increase of 58% from the previous year. The rise in imports is attributable to both the heightened demand for low-sulfur coal to meet the stricter sulfur emission requirements of Phase II of the CAAA, and to the the tight coal supply market that existed for most of 2001.

ELECTRICITY

In 2001, the United States generated 3,779 billion kilowatthours (Kwh) of electricity, including 2,661 billion Kwh at electric utilities plus an additional 1,116 billion Kwh at nonutility producers. For utilities, coal-fired plants accounted for 60% of generation, nuclear 20%, natural gas 10%, hydroelectricity 7%, oil 3%, geothermal and "other" 0.1%. For non-utilities, natural gas plants accounted for around 32% of generation, coal 32%, nuclear 21%, "geothermal and other" (including geothermal, wind, solar, wood and waste) about 8%, oil 5%, hydroelectric at 2%, and "other gaseous fuels" (including refinery still gas and liquefied petroleum gases) 1%. In

general, natural gas-fired power plants have been gaining share the past few years. Coal-fired power plants generally have been less attractive than natural-gas-fired plants due to relatively high capital costs, longer construction periods, and lower efficiencies than natural gas combined-cycle plants.

On a national level, the price of electricity sold by utilities during 2001 averaged 7.16 cents per Kwh, up from 6.68 cents per Kwh during 2000, with higher natural gas input prices largely responsible. Electricity prices in the United States fell every year between 1993 and 1999, but this trend reversed in 2000 and 2001.

As of January 1, 1999, U.S. nameplate generating capacity at electric utilities was 639 gigawatts (GW). Based on primary energy source, coal-fired capacity represented 43% of the nation's existing electric generating capacity in 1999. Natural-gas-fired capacity accounted for 19%; nuclear for 15%; hydroelectricity for 12%; petroleum for 8%; and "renewables" (geothermal, solar, wind) for about 1%. The amount and geographical distribution of capacity by energy source is a function of availability and price of fuels and/or regulations. Capacity by energy source generally shows a geographical pattern such as: significant petroleum-fired capacity in the East, hydroelectric in the West, and natural-gas-fired capacity in the Coastal South.

This summer, total electricity demand is expected to be level with last summer's demand. Cooling degree-days are expected to be somewhat lower than last year, assuming normal weather for May through September. Although the economy is assumed to be growing through the summer months, year-over-year increases in industrial output are not expected to show up until the third quarter of this year.

Over the long term, U.S. power demand is increasing rapidly, with EIA forecasting 1.8% average annual growth in electricity sales through 2020. This increase will require a significant addition in generating capacity, with EIA forecasting that 1,300 new power plants will be needed over the next 20 years. Whether these plants are natural-gas-fired, coal-fired, "renewable," or

nuclear depends on a mix of factors, including economics and government policy, but if recent trends continue, it is likely that the vast majority of new plants will be natural-gas-fired, with oil accounting for less than 1% of power generation by 2020.

The changing structure of the U.S. electric power industry has resulted in many electric utilities restructuring their companies and selling their generating assets, primarily to nonutility companies. During 1999, approximately 55,070 MW of capacity was sold to nonutility companies. On March 31, 1998, retail customers of investor-owned utilities in California (approximately three-fourths of the state's customers) were allowed direct access to an alternative energy (electricity) service provider. Also during 1998, Massachusetts and Rhode Island opened their retail electricity markets. Meanwhile, legislatures and/or public utility commissions in 18 other states (plus the District of Columbia) also have approved or implemented plans to move toward retail competition (although California's problems have caused many of these states to take a second look. On April 2, 2001, Entergy and the FPL Group called off a proposed $7.6-billion merger which would have created the largest power distribution company in the United States. This follows the collapse in 2000 of a proposed $3.3-billion merger between Connecticut's Northeast Utilities and New York's Consolidated Edison Co.

During much of 2000 and early 2001, California confronted a major power problem, with intermittent "rolling blackouts" and "Stage 3" (the highest level) alerts. Causes of this situation included: 1) sharply increased (11%) power demand in California over the past decade as a result of a surging economy and low power costs to consumers; 2) stagnant supply over the same period; 3) low hydropower output levels in the Northwest due to below-normal rainfall; 4) California's heavy reliance on out-of-state capacity and power imports; 5) high natural gas prices and lingering problems from the August 2000 El Paso natural gas pipeline explosion; 6) significant problems stemming from California's Electric Utility Industry Restructuring Act of 1996; and 7) serious financial problems at utilities (PG&E, SCE). Serious problems, however, were largely avoided during the summer of 2001 due to

conservation, a downturn in California's economy (and hence power demand), the addition of power generating capacity, and higher power prices. On September 24, 2001, as required by law, the CPUC effectively put an end to deregulation of retail electricity in California. Although California for the most part avoided power blackouts or other major problems this past summer, financial difficulties continue at utilities like Pacific Gas & Electric (PG&E, in bankruptcy) and Southern California Edison (close to bankruptcy). On October 22, 2001, the US Department of Energy, in partnership with PG&E, announced that it would spend $300 million to upgrade Path 15, a series of power transmission lines connecting northern and southern California. As of early 2002, California had excess power generation and minimal risk of power outages.

In March 2001, the Energy Secretaries of Canada, Mexico, and the United States met to discuss a common energy strategy for the three countries, including integration of the three countries' power grids and creation of a US-Mexican working group to focus on promoting cross-border electricity trade. At present, power trade between Mexico and the United States is severely limited by infrastructure constraints, including inadequate power transmission capability (there are only two cross-border transmission lines: San Diego-Tijuana and El Paso-Matamoros). In January 2001, a small (50-MW), natural-gas-fired power plant in Baja California began exporting power to California. Canada exported about 42.9 bkwh of electricity to the United States in 1999, mostly from Quebec, Ontario, and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Washington state, Minnesota, California, and Oregon. There is considerable reciprocity between the Canadian and U.S. power markets, as the United States also exports smaller volumes of electricity to Canada.

Nuclear

In 2001, U.S. nuclear power generation reached a record 769 billion kWh, or about 20% of total U.S. electricity generation, second only to coal in the U.S. electricity generation mix. Nuclear power's share of U.S. utility electric generating capacity in 2001 was highest in the New England region (69% of

utility generation), followed by the Middle Atlantic (37%), the South Atlantic (29%), the Pacific Coast (24%), the East South Central (20%), the West South Central (17%), the West North Central (16%), the East North Central (12%), and the Mountain region (10%). Approximately one-fourth of U.S. nuclear output was provided by just three statest: Illinois, Pennsylvania, and South Carolina. The average capacity factor for all nuclear units nationwide increased from 88.1% in 2000 to 89.7% in 2001, an all-time record high utilization rate. Following the September 11, 2001 terrorist attacks on the United States, security at nuclear power plants around the United States was increased dramatically.

Nuclear power in the United States grew rapidly after 1973, when only 83 billion kWh of nuclear power was produced. As of 2001, nuclear power had grown nine-fold, with 104 licensed nuclear power units generating 769 billion kWh of electricity. This rapid growth in nuclear power generation, however, obscures serious underlying problems in the U.S. nuclear industry. After 1974, many planned units were canceled, and since 1977, there have been no orders for any new nuclear units, and none are currently planned. The 1979 Three Mile Island accident greatly increased concerns about the safety of nuclear power plants in the United States. The regulatory reaction to those concerns contributed to the decline in the number of planned nuclear units. In late March 2000, the Nuclear Regulatory Commission (NRC), in a positive signal to the U.S. nuclear power industry, granted the first-ever renewal of a nuclear power plant's operating license. The 20-year extension (until 2034 and 2036 for two reactors) went to the 1,700-MW Calvert Cliffs plant in Maryland. As of March 2002, Exelon and Dominion Resources reportedly were looking at sites to build the first new nuclear power plants in the United States in two decades.

After a period of heightened concern for the availability of nuclear generation this summer, the prospect for normal operations appears likely. Upon discovery of corrosion in a major component in a nuclear plant in Ohio, the Nuclear Regulator Commission ordered the submission of safety information on 68 other units, implying the possible need for shutdowns for inspections.It

now appears the problem is confined to one unit and the cause is being investigated.The temporary loss of this capacity is offset by increases in capacity at several reactors due to NRC-approved upgrades ranging from 2% to 20% and totaling several hundred megawatts in each year of the projection. Nuclear generation is expected to be up by about 0.6%-0.7% in 2002 and 2003.

In January 2002, Energy Secretary Spencer Abraham notified Nevada officials that he had formally recommended Yucca Mountain, located 100 miles north of Las Vegas, as the nation's permanent nuclear waste depository. Studies on Yucca Mountain as a possible nuclear power plant waste site have been going on for over two decades, with concerns centering on the dangers of transporting nuclear materials to the site via rail or highway. Nuclear utilities have complained that they are running out of nuclear waste storage capacity at their nuclear plants, with many being forced to resort to "dry cask" storage of spent fuel assemblies after water-storage pools reached capacity.

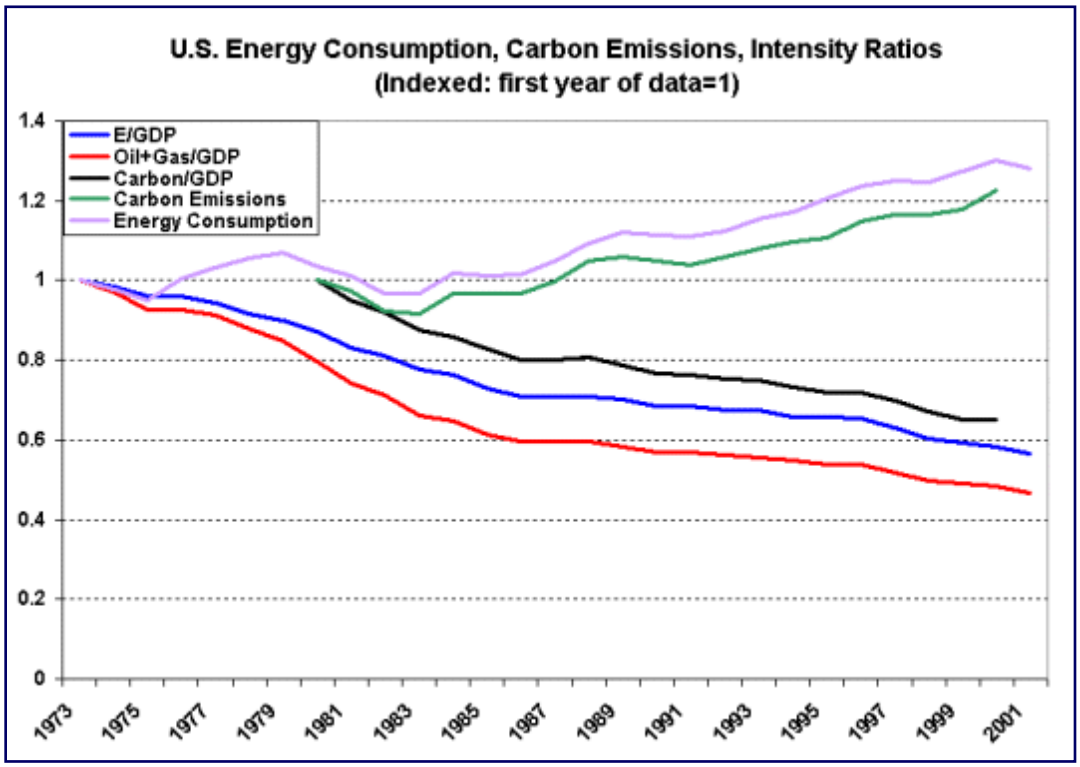
Hydroelectricity/Other "Renewables"

The United States consumed 6.2 quadrillion Btu of renewable energy in 2001, about 6% of total domestic gross energy demand, with the largest component used for electricity production. Hydropower made up around 39% of total U.S. renewable consumption in 2001, with biofuels (including wood and waste), solar, wind, and geothermal making up most of the remainder. In 2001, total hydropower generation was down to lows not seen since 1966. In early 2002, the U.S. Northeast experienced a serious drought, calling into question the adequacy of hydroelectricity supplies during the upcoming summer season. As of May 1, however, the drought appeared to have eased somewhat following heavy rains in much of the region. Overall, total hydro generation is expected to rise by 22% in 2002 if normal precipitation materializes in the Pacific Northwest, the main region affected.

Wind, solar, biomass, and geothermal power, although growing, still supply only a tiny fraction of U.S. energy needs. In January 2000, however, the U.S.

Department of Energy's National Renewable Energy Laboratory (NREL) released a report which said that the domestic photovoltaic (PV) industry could provide up to 15% of "new U.S. peak electricity capacity expected to be required in 2020." Wind, geothermal, and biomass energy sources also have significant potential in the United States.

In 2001, 1,694 MW of wind power was installed in the United States, more than twice the previous record of 732 MW installed in 1999, according to the American Wind Energy Association (AWEA). This increase, driven in part by a federal wind production tax credit, boosted total U.S. installed wind generating capacity to 4,258 MW, with wind turbines now located in 26 states. The first U.S. offshore windmill park reportedly is scheduled to be built off the Cape Cod coast, with 170 windmills to be installed beginning in 2004. The project could power more than 200,000 homes in Cape Cod.



ENVIRONMENT

The United States, with the world's largest economy, is also the world's largest single source of anthropogenic (human-caused) greenhouse gas emissions. Quantitatively, the most important anthropogenic greenhouse gas emission is carbon dioxide, which is released into the atmosphere when fossil fuels (i.e., oil, coal, natural gas) are burned. Current projections indicate that U.S. emissions of carbon (mainly in the form of carbon dioxide) will reach 1,694 million metric tons in 2005, an increase of 357 million metric tons from the 1,337 million metric tons emitted in 1990, and around one-fourth of total

world energy-related carbon emissions. At the December 1997 global warming summit in Kyoto, Japan, the U.S. delegation agreed to reduce U.S. carbon emissions 7% from 1990 levels by 2008-2012. Given current EIA projections, it is unlikely that this goal will be met. In February 2002, the Bush Administration released its proposed alternative to the Kyoto Treaty, calling for significant reductions in emissions of various pollutants (mercury, nitrogen oxide, sulfur dioxide). The program, known as the "Clear Skies Initiative," would utilize a "cap and trade" system which would allow companies to trade emissions credits. In addition, the Bush Administration envisions reductions in U.S. "greenhouse gas intensity" -- the amount of greenhouse gases emitted per dollar of GDP -- by 18% over 10 years. As the graph here shows, U.S. carbon emissions per dollar of GDP have been declining steadily since at least 1980.

U.S. energy-related carbon emissions have been increasing in recent years for three main reasons. First, the U.S. economy experienced strong economic growth during the 1990s, which in combination with generally low oil prices for most of the period (until recently), caused energy consumption to increase. Second, the energy "efficiency gains" of the 1980s, which were prompted largely by the oil price spikes of the 1970s, have been leveling off for several years now, particularly since the 1985/86 oil price collapse. Sales of sport-utility vehicles, minivans, and small trucks, for instance, all of which are less fuel efficient than small cars, have increased sharply in recent years. Third, nuclear power generation (which emits no carbon), has now stagnated and is expected to decline after expanding rapidly during the 1970s and 1980s. Hydroelectricity, the other major non-fossil energy source in the United States, also has not been growing.

Since taking office on January 20, 2001, the Bush Administration has taken a series of actions related to energy and the environment. On February 28, 2001, EPA Administrator Christine Todd Whitman directed her agency to move ahead with a rule issued by President Clinton that will require U.S. refiners to reduce sulfur in diesel fuel from 500 parts per million currently, to 15 parts per million by 2006. On March 13, 2001, President Bush declared

that his administration would not seek to regulate power plants' emissions of carbon dioxide, citing an EIA study that regulating these emissions could result in higher electricity prices. On March 27, the Bush administration declared that the United States had "no interest" in implementing or ratifying the Kyoto treaty, saying it would be too harmful to the U.S. economy, and that it would pursue other ways of addressing the climate change issue. On April 10, the EPA asked the U.S. Court of Appeals in Washington, DC to uphold a Clinton administration plan to regulate mercury pollution from coal-fired power plants, beginning in 2004. On April 12, the White House affirmed Clinton administration-approved energy efficiency standards for washing machines and water heaters. Under these standards, clothes washers would become 22% more efficient by 2004 and 35% more by 2007. The next day (April 13), the Department of Energy announced that it would require air conditioners to be 20% more energy efficient by 2006. The Clinton administration had mandated a 30% energy efficiency increase for air conditioners. In January 2002, Energy Secretary Spencer Abraham announced an initiative, known as "Freedom CAR," to help automakers produce fuel-cell-powered electric vehicles.

COUNTRY OVERVIEW

President: George W. Bush (since January 20, 2001)
Legislative Branch: Bicameral Congress (Senate, House of Representatives)
Judicial Branch: Supreme Court
Independence: July 4, 1776
Population (July 2001E): 278 million
Location/Size: North America, between Canada and Mexico/9,629,091 sq. km (3,717,792 sq. miles)., the third largest country in the world, behind Russia and Canada
Major Cities: Washington, DC (capital), New York, Los Angeles, Chicago, Houston, Miami, Philadelphia, etc.
Languages: English, Spanish (spoken by a sizable minority)
Ethnic Groups (8/1/2000): White (82.2%), Black (12.8%), Asian (4.1%), Native American (0.9%). Note: Hispanics, who can be of any race, made up 11.8% of the U.S. population as of 8/1/2000.

Religions (1997): Protestant (58%), Roman Catholic (26%), Jewish (2%), other (6%), none (8%)
Defense (8/98): Army, 479,400; Navy, 380,600; Air Force, 370,300; Marine Corps, 171,300 (the United States also has nearly 1.35 million reservists)

ECONOMIC OVERVIEW

Currency: Dollar ($)
Exchange Rates, per Dollar (10/25/2001): British Pound (0.6992); Canadian Dollar (1.58); Euro (1.1259); French Franc (7.3201), German Mark (2.1825); Japanese Yen (122.68)
Gross Domestic Product (GDP) (2001E): $10.3 trillion
Real GDP Growth Rate: (2001E): 1.2% **(2002F):** 1.6% **(2003F):** 3.8%
Inflation Rate (GDP implicit price deflator) (2001E): 2.2% **(2002F):** 1.5% **(2003F):** 2.1%
Unemployment Rate (2000E): 4.2% **(2001E):** 4.8%
Current Account Balance (2000E): -$435.4 billion **(2001E):** -$453 billion
Merchandise Exports (2001E): $1,081 billion **(2002F):** $1,021 billion
Merchandise Imports (2001E): $1,494 billion **(2002F):** $1,458 billion
Merchandise Trade Balance (2001E): -$413 billion **(2002F):** -$437 billion
Major Exports (1999): Capital goods excluding automobiles ($312 billion), industrial supplies ($142 billion), consumer goods excluding autos ($81 billion), motor vehicles and parts ($76 billion), services ($291 billion)
Major Imports (1999): Capital goods excluding autos ($297 billion), consumer goods excluding autos ($240 billion), motor vehicles and parts ($179 billion), industrial supplies excluding oil ($149 billion), petroleum and products ($68 billion), services ($196 billion)
Major Trading Partners: Canada, Japan, European Union, Mexico

ENERGY OVERVIEW

Secretary of Energy: Spencer Abraham (as of January 20, 2001)
Proven Oil Reserves (1/1/02E): 22.0 billion barrels
Oil Production (2001E): 8.1 million barrels per day (bbl/d), of which 5.9 million bbl/d is crude oil (NOTE: Including "refinery gain," US oil production in 2001 is estimated at 9.0 million bbl/d)

Oil Consumption (2001E): 19.6 million bbl/d
Net Oil Imports (2001E): 10.6 million bbl/d
Crude Oil Imports from the Persian Gulf (2001E): 2.6 million bbl/d (around 29% of total U.S. crude oil imports)
Value of Oil Imports (2001E): $97.0 billion (down from $119.3 billion in 2000)
Crude Oil Refining Capacity (2002E): 16.5 million bbl/d (91% utilization rate as of 10/12/01)
Oil Stocks (8/01E): 1.55 billion barrels (including about 545 million barrels in the U.S. Strategic Petroleum Reserve)
Oil Wells Drilled (2001E): 7,949 (up from 7,358 in 2000)
Operating Oil and Natural Gas Rotary Rigs (2/02E): 825 (679 for natural gas and 144 for oil)
Natural Gas Reserves (1/1/02E): 177 trillion cubic feet (Tcf)
Dry Natural Gas Production (2001E): 19.1 Tcf
Natural Gas Consumption (2001E): 22.7 Tcf
Net Natural Gas Imports (2001E): 3.5 Tcf (over 90% from Canada)
Natural Gas Wells Drilled (2001E): 21,224 (up from 15,598 in 2000)
Recoverable Coal Reserves (12/31/98): 275.1 billion short tons (54% lignite and subbituminous; 46% anthracite and bituminous)
Coal Production (2001E): 1,121 million short tons (Mmst)
Coal Consumption (2001E): 1,081 Mmst
Gross Coal Exports (2001E): 49 Mmst
Value of Coal Exports (1999E): $2.5 billion
Coal Stocks (12/01E): 171.1 Mmst
Electric Utility Generation Capacity (1/1/99E): 639 gigawatts (coal 43%, natural gas 19%, nuclear 15%, hydroelectric and other renewables 13%, and petroleum 8%)
Electric Net Generation by Utilities (2001E): 2,661 billion kilowatthours (of which coal-fired 60%, nuclear 20%, natural gas 10%, hydroelectricity 7%, oil 3%, geothermal and "other" 0.1%)
Non-utility Power Production (2001E): 1,116 billion kilowatthours (of which natural gas-fired 32%, coal 32%, nuclear 21%, "geothermal and other"

8%, oil 4%, hydroelectric 2%, and "other gaseous fuels" 2%)
Total Electricity Generation (2001E): 3,779 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Administrator of the U.S. Environmental Protection Agency: Christine Todd Whitman
Total Energy Consumption (2001E): 97.0 quadrillion Btu (25% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 1,583 million metric tons of carbon (about 25% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 348.9 million Btu
Per Capita Carbon Emissions (2000E): 5.7 metric tons of carbon
Energy Intensity (2001E): 10,390 Btu/$1996
Carbon Intensity (2000E): 0.17 metric tons of carbon/thousand $1996
Sectoral Share of Energy Consumption (2001E): Industrial (35%), Transportation (26%), Residential (21%), Commercial (18%)
Sectoral Share of Carbon Emissions (1998E): Industrial (32.6%), Transportation (32.0%), Residential (19.4%), Commercial (16.0%)
Fuel Share of Energy Consumption (2001E): Oil (39%), Natural Gas (23%), Coal (23%), Renewables (6%)
Fuel Share of Carbon Emissions (2000E): Oil (42%), Coal (37%), Natural Gas (21%)
Renewable Energy Consumption (2001E): 6,173 trillion Btu (about 39% of which was conventional hydroelectric power)
Number of People per Motor Vehicle (2000E): 1.3
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified October 15th, 1992). Under the negotiated Kyoto Protocol (signed on November 12th, 1998 - not yet ratified), the United States agreed to reduce greenhouse gases 7% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Air pollution resulting in acid rain in both the US and Canada; the US is the largest single emitter of carbon dioxide from the burning of fossil fuels; water pollution from runoff of pesticides and fertilizers; very limited natural fresh water resources in much of the western

part of the country require careful management; desertification.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Antarctic-Environmental Protocol, Antarctic Treaty, Climate Change, Endangered Species, Environmental Modification, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified, Air Pollution-Persistent Organic Pollutants, Air Pollution-Volatile Organic Compounds, Biodiversity, Desertification, Hazardous Wastes.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

ENERGY INDUSTRY
Major U.S. Oil Companies: ExxonMobil, Texaco, Chevron, BP, Shell, USX, Phillips, Conoco
Major U.S. Coal Companies: Peabody Holding Co., Inc.; Cyprus AMAX Minerals Co.; Consol Energy Inc.; Kennecott Energy Co.; Zeigler Coal Holding Co.
Oil Pipelines (2001E): Around 2 million miles **Natural Gas Pipelines (2000E):** 278,000 miles
Major Ports: Baltimore, Chicago, Hampton Roads, Houston, Los Angeles, New Orleans, New York, Philadelphia

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Sources for this report include: Associated Press; Christian Science Monitor; Dallas Morning News; Dow Jones; DRI/WEFA; EIU Viewswire; Energy Daily; Financial Times; Financial Times Energy Newsletters; Gas Daily; Houston Chronicle; Los Angeles Times; Megawatt Daily; New York Times;

PR Newswire; Reuters; U.S. Energy Information Administration (numerous publications -- see links); Washington Post; World Markets Online 2001).

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LINKS

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U.S. Department of Energy's Office of Fossil Energy Home Page
U.S. Department of Energy Home Page
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Energy Information Administration

July 2002

Caspian Sea Region: Oil Export Options

The collapse of the Soviet Union in 1991 opened up new opportunities for oil companies and international investors in the Caspian Sea region. The tremendous oil production potential in the Sea and the surrounding region has led to a boom in investment and fierce competition for exploration and development rights. During the Soviet era, oil exports from the Caspian Sea region were routed through Russia. Now that they are independent, Azerbaijan, Kazakhstan, and Turkmenistan, with the help of foreign investment, are seeking to increase their oil production and to diversify their export options. As oil from the Caspian region begins to flow in greater amounts, new pipelines will be needed to carry this oil from the Caspian to world markets.

Due to the Caspian region's relative geographical isolation, building new infrastructure to deliver the region's oil to consumers will be expensive. Geopolitical considerations, as well as the unresolved legal status of the Caspian Sea, are additional issues complicating the construction of export pipelines. Finally, several regional conflicts may prove to dissuade international investors from financing pipelines. Nevertheless, the region's bountiful oil production potential has meant that a number of Caspian oil export pipelines have been proposed. The United States has supported the principle of providing multiple export options for the Caspian's oil-producing countries, but it has discouraged export routes through Iran by enacting the Iran and Libya Sanctions Act.

West, to the Black Sea via Georgia

As part of the Eurasian Transport Corridor (TRACECA) transporting goods to Europe from the Caucasus, Georgia is set to become a major transit point for Caspian region oil.

Baku-Supsa

On March 8, 1996, Georgian President Eduard Shevardnadze and Azerbaijani President Heydar Aliyev signed a 30-year agreement to pump a portion of the "early oil" from the Azerbaijan International Operating Company (AIOC)'s production-sharing agreement in the Azeri, Chirag, and the deepwater portions of the Gunashli field through Georgia. The so-called "western route" for the AIOC early oil runs from Baku to the Georgian port of Supsa on the Black Sea.

The Georgian International Oil Company, a subsidiary of the AIOC, made substantial upgrades to the existing pipeline along this route and built the $565 million Supsa terminal on the Black Sea. The 515-mile, 100,000-bbl/d-capacity pipeline became operational in April 1999, with oil being pumped through Georgia at 18 cents per barrel. Officials from British Petroleum (BP), the operator of AIOC, said that the consortium exported approximately 130,000 bbl/d in 2001, with virtually all of its oil available for export being shipped to Supsa.

Recent upgrades have raised capacity on the Baku-Supsa pipeline to approximately 145,000 bbl/d. Proposals have been made to increase throughput along this route from the original design capacity of 100,000 barrels per day (bbl/d) to 300,000 bbl/d or even 600,000 bbl/d, but AIOC has focused its efforts on pushing ahead with the Baku-Ceyhan pipeline instead.

Rail and Smaller Pipeline Options

Oil from the Caspian region also could transit Georgia to its Black Sea ports via several smaller pipelines. Georgia already is playing a major role as a rail transit center for Caspian Sea oil, as it has been carrying oil from Azerbaijan and Kazakhstan by rail to its Black Sea ports since 1997.

Prior to the opening of the Caspian Pipeline Consortium's (CPC) Tengiz-Novorossiisk pipeline in the fall of 2001, ChevronTexaco had been delivering oil from the Tengiz field in Kazakhstan via the Caucasus. ChevronTexaco sent its oil across the Caspian by barge to the Dubendi terminal in Azerbaijan, where it was further transported via a pipeline to Ali-Bayramly (Azerbaijan), and then to Georgia's Black Sea port at Batumi in rail cars.

In September 1999, Chevron (now ChevronTexaco) and Georgian company Geoengineering signed an agreement on the preparation of a feasibility study for the reconstruction of the 105-mile pipeline from Khashuri to the port of Batumi, with an eye towards using the pipeline for transiting Tengiz crude. Together with an upgrade of the Batumi refinery, the project was estimated to cost $100 million.With the launch of the CPC, however, ChevronTexaco decided in May 2001 to cancel the project to reconstruct the Khashuri-Batumi pipeline, saying that the pipeline was economically unfeasible, especially since most of the Tengizchevroil exports are now routed via the CPC.

Nevertheless, Tengiz crude has been replaced at the Batumi port by high-quality Kumkol crude, supplied by Euro Asian Trading, and the lower-quality Buzachi blend, produced by Kazakhstan's Mangistaumunaigaz, both of which reach Batumi via a combination of barge, pipeline, and rail across the Caspian and the Caucasus. Turkmenistan also exports occasional cargoes of Cheleken and Okarem crude, which are mostly blended with the Kazakh oil either at the Batumi terminal or on barges, forming a "synthetic Urals" blend.

In order to accommodate more Caspian region oil transiting its territory, Georgia is upgrading its Black Sea ports and constructing new terminals. The Supsa and Batumi ports have been upgraded, and in May 2001, the EBRD agreed to finance the construction of a $20 million oil terminal at the Black Sea port of Poti. The Poti terminal will be able to handle up to 50,000 bbl/d, proving an alternative to the main port at Batumi.

In addition, Georgia and Turkey are working on plans to utilize a 172-mile railway line between Tbilisi and Kars, Turkey, to transport up to 200,000 bbl/d of crude oil from the planned Baku-Ceyhan pipeline to Turkish refineries. The railway plan, which could cost $400 million, will require refurbishing an existing line from Tbilisi to Akhalkalaki for $200 million, as well as extending the rail line 77miles to Kars.

West, to the Mediterranean Sea via Georgia and Turkey

In November 1999, Azerbaijan, Georgia, and Turkey signed agreements affirming the Baku-Ceyhan route as the Main Export Pipeline (MEP) for Azeri oil exports.

Baku-Ceyhan

The planned 1-million-bbl/d capacity, "Main Export Pipeline," which has received backing from the United States, will stretch approximately 1,038 miles (281 miles through Azerbaijan, 135 miles through Georgia, and 622 miles through Turkey) and is expected to cost between $2.8 billion and $2.9 billion to construct. Despite initial opposition to the pipeline, which several oil companies criticized as too costly and uneconomical with the planned volumes from Azerbaijan, construction on the Turkish section of the pipeline began in June 2002. The entire pipeline is expected to be finished in late 2004, with the first tanker leaving Ceyhan with Azeri oil in January 2005.

Despite earlier misgivings, BP, the operarator of the AIOC consortium that is expected to fill the pipeline, threw its support behind the Baku-Ceyhan proposal in 1999. BP had been opposed to the project, citing doubts that enough oil has been found to justify the high costs. However, BP revised downwards the amount of oil reserves that would be needed to make the pipeline economical, from 6 billion barrels to a more achievable 4 billion to 4.5 billion barrels.

Following the completion of a basic, 6-month engineering study in May 2001, the pipeline's sponsorship group, led by seven international oil companies and the State Oil Company of the Azerbaijan Republic (SOCAR), undertook a one-year, $150 million, detailed engineering feasibility study for the pipeline in Azerbaijan and Georgia (Turkish pipeline company Botas is responsible for the Turkish section of the pipeline). The detailed engineering study, covering all issues relating to the final details of the route, including the type of line pipe to be used, the pumps and pumping stations requirements, was completed in 2002.

Although construction on the Turkish section of the pipeline already has begun, financing for the Azeri and Georgian sections is still being arranged. Credits from international financial organizations are expected to finance 70% of the cost, with the remaining 30% coming from the pipeline sponsor group, which will become the Main Export Pipeline Company (MEPCO). Currently, seven of the ten members of the AIOC consortium are members of the sponsor group, with only Lukoil, ExxonMobil, and Devon Energy not members. SOCAR, which originally had a 50% stake in the sponsor group, sold ENI (Italy)--a non-member of AIOC--a 5% share in the pipeline project in October 2001.

After failing to come to agreement with other energy companies to join the sponsor group, in March 2002 SOCAR reduced its stake in the pipeline project to 25%, distributing 20% among other group members. In June 2002, SOCAR sold an additional 5% share to TotalFinaElf (France-Belgium), but rejected a proposal from ChevronTexaco to join the sponsor group. At the end of June 2002, the head of the sponsorship group, Michael Townshend of BP, said that the pipeline ownership group was complete. Shares in MEPCO are as follows: BP (38.21%), SOCAR (20%), Unocal (9.58%), Statoil (8.9%), TPAO (7.55%), TotalFinaElf (5%), ENI (5%), Itochu (3.4%), and Delta Hess (2.36%). .

North and Northwest, via Russia

Prior to the breakup of the Soviet Union, there was only one major crude export pipeline--the 240,000-bbl/d Atyrau-Samara pipeline from Kazakhstan to Russia--that connected Caspian Sea oil production to the Russian crude oil export pipeline system and world markets. However, the current proliferation of proposed export routes has put Russia in the position of having to compete with other export outlets for Caspian oil. Thus, Russia is looking to become a transit center for Caspian region oil. In June 2002, Kazakhstan and Russia signed a 15-year oil transit agreement under which Kazakhstan will export at least 350,000 bbl/d of oil annually via Russia, in addition to flows via the CPC.

Tengiz-Novorossiisk

In March 2001, the Caspian Pipeline Consortium (CPC) commissioned its $2.5 billion, 1.34 million-bbl/d-capacity pipeline, sending oil flowing 990 miles from Tengiz to Novorossiisk. After several customs problems and technical delays, the first oil was loaded onto a tanker in Novorossiisk in October 2001, and in November 2001, CPC shareholders decided on a transportation tariff of $26.32 per 1,000 tons ($3.59 per barrel) per 100 kilometers (62.5 miles). The CPC exported approximately 240,000 bbl/d in April 2002, with volumes expected to rise to 400,000 bbl/d by the end of 2002 once additional pumping stations and pipeline links are completed.

Preliminary plans are to increase exports to 520,000 bbl/d in 2003, but the pipeline is not scheduled to reach its full capacity until about 2015. ChevronTexaco, which operates the Tengizchevroil joint venture that currently is supplying the majority of to the pipeline, has estimated that during its 35 to 40 year expected life, the pipeline could bring in $8 billion in taxes for Kazakhstan, and development of the Tengiz field and operation of the pipeline would earn about $150 billion for Kazakhstan and Russia.

Since both Kazakh and Russian oil will be piped via the line, creating a new "CPC Blend" of oil, Kazakh and Russian officials created a "quality bank" to compensate higher-quality Kazakh oil exporters whose oil quality is diluted by the new blend. The Tengizchevroil joint venture will transport approximately 240,000 bbl/d via the pipeline in 2002, with future plans to export an additional 120,000 bbl/d per year via the pipeline from the Karachaganak field in Kazakshtan.

Turkey has raised concerns about the ability of the Bosporus Straits to handle additional tanker traffic that will be necessary to handle the planned volume of Kazakh oil to be exported via the CPC pipeline. Turkey has expressed its concern that the Straits, already a major chokepoint for oil tankers, cannot handle the strain of additional traffic, raising environmental concerns about a collision

leading to an oil spill in the Straits. Although Kazakhstan has argued against limiting oil tanker traffic through the Straits, a number of "Bosporus bypass" options are under consideration or being developed in southeastern Europe. In addition, Ukraine already has constructed a new pipeline, the Odessa-Brody pipeline, specifically to transport oil from the Caspian Sea region to European markets.

Atyrau-Samara

In recent years, Kazakhstan's oil exports, which compete with Russian oil exports, have been limited by Kazakhstan's annual oil export quota through the Atyrau-Samara pipeline and the Russian pipeline system. (The CPC pipeline is not part of the Transneft-controlled Russian pipeline system.) With oil production in Kazakhstan on the rise, Kazakhstan is interested in gaining improved access to oil terminals in the Baltic Sea for its oil exports via the Atyrau-Samara pipeline. Although Kazakhstan has supplied a small amount of oil to Lithuanian terminals, deliveries have been delayed due to the lack of an agreement with Russia on transportation tariffs.

Since Kazakhstan now has an alternate oil export route via the CPC pipeline, Russian pipeline monopoly Transneft is looking to attract more Kazakh oil via the Atyrau-Samara pipeline. Russia recently completed an expansion of the 432-mile pipeline that increased its capacity to 310,000 bbl/d, and Russia has increased Kazakhstan's export quotas and lowered its pipeline tariffs. With the opening of Russia's new Baltic Pipeline System (BPS) in December 2001, Russia is keen to export Kazakh oil through its own Baltic Sea terminal at Primorsk. In an effort to fill the BPS and to profit from Kazakh oil transiting its territory, Russia allocated a 100,000 bbl/d quota of Kazakh oil for the BPS. The June 2002 transit agreement between Kazakhstan and Russia guarantees Kazakhstan the ability to pipe 300,000 bbl/d through the Atyrau-Samara pipeline.

Baku-Novorossiisk

The 100,000-bbl/d-capacity Baku-Novorossiisk pipeline, also known as the "northern route", opened in 1997. The pipeline runs 868 miles from Baku via Chechnya to the Russian Black Sea port of Novorossiisk. Initial exports through the pipeline were limited to approximately 40,000 bbl/d, however, owing to pumping limitations, disputes over transit tariffs, and the conflict in Chechnya. Up to 70,000 bbl/d of oil was forced to bypass Chechnya by rail from Dagestan to Stavropol.

The ongoing conflict and instability in Chechnya prompted Russian pipeline operator Transneft to construct a 120,000-bbl/d Chechnya pipeline bypass (160,000 bbl/d including rail links). In 2000, Azerbaijan's SOCAR committed itself to throughput of 46,000 bbl/d, but in the end only transported around 10,000 bbl/d, prompting Transneft to accuse Azerbaijan of not fulfilling its commitment to export oil along the bypass. In addition, the AIOC, which also was expected to export via Baku-Novorossiisk, has been reluctant to pipe its oil along this route, since it is longer and more expensive than the Baku-Supsa route, and also because the northern route mixes AIOC crude with other crude oils while in transit to Novorossiisk, reducing its value.

SOCAR exported approximately 50,000 bbl/d via the Baku-Novorossiisk route in 2001, and plans to maintain that rate in 2002. According to SOCAR, 2001 exports via the northern route increased because SOCAR refined 40,000 bbl/d less than in 2000; as Azerbaijan imported Russian natural gas, SOCAR significantly reduced production of fuel oil for local power stations and exported all of the surplus crude oil via the Baku-Novorossiisk pipeline. Russia says the the capacity on Baku-Novorossiisk can be increased to 300,000 bbl/d, but SOCAR will not have sufficient volumes to fill the pipeline, even at its present capacity, in the next few years.

A 1996 oil transit agreement between Russia and Azerbaijan is scheduled to terminate at the end of 2003, but the agreement will remain valid until one of the sides withdraws from it. Neither side is happy with the deal, however, and both sides want to resolve disagreements on oil quality, tariffs, and pumping volumes. For its part, Transneft wants to have a guaranteed amount of oil for several years in advance, so Russia has offered to pay for an increase in capacity in the Baku-Novorossiisk pipeline if Azerbaijan commits to shipping larger volumes of crude oil through the system over the long term.

SOCAR officials, on the other hand, are unhappy with the high tariffs and the absence of an oil quality bank for the Baku-Novorossiisk pipeline. SOCAR Deputy Chairman Ilham Aliyev has said that, due to differences in tariffs between the Baku-Supsa and Baku-Novorossiisk pipeline, Azerbaijan loses $13 million per every million tons (20,000 bbl/d) transported via the Baku-Novorossiisk route.

In addition, because the northern pipeline mixes high-quality Azeri Light with low-quality oil from other regions, Azeri oil exported via Novorossiisk is sold at a discount to Azeri oil exported via Baku-Supsa. Azeri officials would like to introduce an "oil quality bank" for the Baku-Novorossiisk pipeline, in which shippers who pipe low-quality oil via the pipeline would compensate Azerbaijan

for the reduction in price of its high-quality Azeri Light at the pipeline's terminus. Currently, neither the Russian government nor the other exporters who use Baku-Novorossiisk compensate Azerbaijan for mixing their oils with Azeri oil and reducing its value.

Thus, with exports of 50,000 bbl/d in 2001, Aliyev estimated that Azerbaijan lost between $40 million and $50 million in added revenues by exporting via the Baku-Novorossiisk pipeline. Nevertheless, Russia insists that future Azeri oil should run to its port of Novorossiisk on the Black Sea, pointing out that Baku-Novorossiisk can be expanded and the transit costs via the pipeline could be a little as half the $3 per barrel that the proposed Baku-Ceyhan is expected to cost. However, future Azeri oil production, mainly from the AIOC, is slated to be exported via the Baku-Ceyhan pipeline.

Additional Export Options

In addition to the Baltic Pipeline System, Russia could export Caspian region oil to world markets via its pipeline system using Adriatic ports. By connecting the southern Druzhba pipeline with the Adria pipeline in Croatia, then reversing flows in the Adria, Russia could ship oil via the Croatian port of Omisalj, thereby allowing oil exporters to bypass the Bosporus Straits.

The Russian Transport Ministry also has proposed shipping oil via barge and tanker from Turkmenistan and Kazakhstan to Russian Caspian Sea ports such as Makhachkala and Astrakhan. From there, the oil could be sent by rail to the Russian ports of Novorossiisk and Tuapse on the Black Sea; Kazakh rail exports from the Tengiz oil field through Russia totaled approximately 100,000 bbl/d in 2000. The Transport Ministry said that total shipments from Turkmenistan could increase to 240,000 bbl/d as port facilities in Kazakhstan and Turkmenistan are upgraded and expanded. Turkmenistan is planning to export about 20,000 bbl/d via Makhachkala-Novorossiisk pipeline in 2002.

South, to the Persian Gulf via Iran

Iran has long maintained that routes through Iran to the Persian Gulf are the shortest and most economical for exporting oil from the Caspian Sea. In addition, the Persian Gulf routes would transport oil to Asia, where the demand for oil is projected to grow faster and command a higher price than the Mediterranean markets that most of the competing pipelines would serve.

Oil could be exported via Iran in two ways: by direct transportation by pipelines that pass through Iran en route to the Persian Gulf, or by oil swaps. However, any large investment in Iran's oil sector would be problematic due to direct U.S. economic sanctions and additional sanctions as dictated by the Iran and Libya Sanctions Act.

Oil Swaps

Iran has been promoting oil swaps via its proposed 370,000-bbl/d pipeline from its Caspian Sea port of Neka. Under this arrangement, oil will be shipped to Iran's Caspian Sea ports and transported via pipeline, rail, and tanker trucks to refineries located in northern Iran. In exchange, Iran would deliver a similar volume of crude oil to its Persian Gulf Coast, where Caspian exporters could ship their oil to consumers.

Under a 1996 agreement, up to 120,000 bbl/d of Kazakh oil was to be delivered by tanker via the Caspian Sea to the Iranian port of Neka, where it would travel by pipeline to a refinery at Tabriz to be refined and consumed locally. In exchange, Kazakhstan would receive a similar volume of crude ready for export at an Iranian port in the Persian Gulf. Kazakhstan and Iran have been trying to negotiate a supply deal for years, but previously Kazakh crude has proved incompatible with Iranian refineries and there have been disagreements over price.

Volumes also have been limited by contract and technical issues, including the initial problems by Iranian refineries in processing Kazakh crude oil. In the first quarter of 2002, Kazakhstan began making test deliveries to Neka of about 1,600 bbl/d. Kazakh officials hoped to increase the swaps to 17,000 bbl/d, but that appears to be unlikely at this time.

Turkmenistan increasingly has turned to swap agreements with Iran in order to export its oil, with Turkmen oil being delivered to the Iranian Caspian port of Neka. The oil swaps began in July 1998. Dragon Oil, which produced approximately 7,000 bbl/d in 2001 in a production-sharing agreement with Turkmenistan, has exported its share of this production through a swap deal with Iran since 1998, and in April 2000 the company signed a new 10-year swap agreement with Iran.

However, a major problem with swaps is the U.S. sanctions against Iran. U.S. economic sanctions on Iran have prohibited American oil companies with investments in the Caspian Sea region from participating in large-scale oil swaps with Iran; in April 1999,

ExxonMobil's application for a license to swap Turkmen oil for Iranian oil was denied. The Iran-Libya Sanctions Act seeks to penalize non-U.S. firms from doing business with Iran, and as a result, it remains to be seen whether Kazakhstan and Turkmenistan will choose to increase swaps with Iran.

Kazakhstan-Turkmenistan-Iran

Several possibilities are available for direct transportation of Caspian oil to the Persian Gulf. One proposed pipeline would carry Kazakh oil via Turkmenistan to the middle of Iran, then connect to Iran's existing pipeline network and transport oil south to Iran's Persian Gulf ports. Iran has suggested that Azerbaijan also could transport its oil via this pipeline by shipping oil eastwards across the Caspian to the port of Turkmenbashi, Turkmenistan, where it could connect with the proposed Kazakhstan-Iran pipeline

In April 2002, Kazakh President Nursultan Nazarbayev, in a meeting with Iranian President Mohammed Khatami, stated that an oil pipeline route through Iran would be the most economical way to export Kazakh oil. Kazmunaigaz, the new Kazakh state oil and natural gas company, currently is in talks with TotalFinaElf to prepare a feasibility study for a pipeline from Kazakhstan to Iran. The proposed 900-mile, $1.2-billion pipeline would have a capacity of 1-million bbl/d.

Iran-Azerbaijan

Iran also has proposed a pipeline that would transport oil from Baku via a proposed 190-mile pipeline to northwest Iran, where it would connect with the existing Iranian pipeline network and refineries. TotalFinaElf, which has a large presence in Iran, has proposed building a pipeline with capacity of between 200,000 bbl/d and 400,000 bbl/d, and in May 2001, Iran's oil ministry authorized the construction of a refinery close to the Caspian sea near the border with Azerbaijan. However, Azerbaijan has indicated that progress on disputes with Iran concerning the division of the Caspian would need to occur before such a project moved forward, as well as Iranian progress towards improved relations with the West.

Southeast, to Pakistan via Afghanistan

Turkmenistan has signed a memorandum of understanding with Afghanistan and Pakistan to build a 1-million bbl/d pipeline to carry oil to Pakistan and world markets via Afghanistan. In October 1997, a tripartite commission comprising Afghanistan, Turkmenistan, and Pakistan was formed to start work on building the so-called "Central Asian Oil Pipeline" (CAOP).

However, no progress has made on the pipeline due to the instability in Afghanistan. Following the August 20, 1998, U.S. bombing raids on suspected Afghan strongholds of suspected terrorist Osama bin Laden, Unocal announced that it was suspending work on the pipeline, and in December 1998, it withdrew from the consortium formed to build the pipeline.

Since the Taliban government's ouster in December 2001, discussions regarding the Central Asian Oil Pipeline have resurfaced. U.S. Deputy Secretary of State Elizabeth Jones, during a January 2002 visit to Ashgabat, stated that the U.S. would support private companies that chose to undertake trans-Afghanistan pipeline projects if they were considered to be beneficial and commercially viable. Continuing unrest in Afghanistan has stalled any progress on the CAOP.

East, to China

Kazakhstan also is considering the Chinese market. Kazakhstan exported 50,000 bbl/d to China by rail in 1999, and Tengizchevroil has made test deliveries to China by rail. In June 1997, the China National Petroleum Corporation signed an agreement with Kazakhstan for a proposed $3.5 billion, 1,800-mile pipeline to China that would be financed by China. A feasibility study for the pipeline was undertaken, but the study was halted near its completion date. In order to make the project economically feasible, Kazakhstan would have to guarantee 500,000 bbl/d per year through the pipeline, a level to which Kazakhstan said it could not commit.

Trans-Caspian Sea Routes

The amount of oil that is sent by barge across the Caspian Sea is expected to rise further with expansions to pipeline, port, and rail infrastructure in Caspian region countries. In addition to the large volume of oil that already is being shipped by barge across the Sea, several trans-Caspian oil export pipeline options have been proposed.

As Caspian region production increases, trans-Caspian pipelines could bring increasing volumes of oil from Kazakhstan and Turkmenistan across the Caspian. The trans-Caspian pipelines would connect with other export pipelines from the Caspian region, such as the proposed Main Export Pipeline. Eventually, the cross-Caspian pipelines could be connected on the east with export routes flowing eastward as well. In December 1998, Royal Dutch/Shell, Chevron, and ExxonMobil signed an agreement with Kazakhstan to

conduct a feasibility study for twin oil and natural gas pipelines that would pass across the Caspian Sea from Aqtau in western Kazakhstan to Baku.

However, the the idea of constructing trans-Caspian pipelines thus far has met with resistance. In addition to the legal issues relating to use of the Sea, Russia and Iran have raised environmental concerns about the impact of pipelines on the seafloor. Both countries have stated their oppostition to the laying of trans-Caspian pipelines on ecological grounds. Territorial disputes need to be resolved as well.

Oil Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Crude Capacity	Length	Cost/Investment	Status
Atyrau-Samara Pipeline	Atyrau (Kazakhstan) to Samara (Russia), linking to Russian pipeline system	Recently increased to 310,000 bbl/d	432 miles	Increase in capacity cost approximately $37.5 million	Existing pipeline recently upgraded by adding pumping and heating stations to increase capacity.
Baku-Ceyhan ("Main Export Pipeline")	Baku (Azerbaijan) via Tbilisi (Georgia) to Ceyhan (Turkey), terminating at the Ceyhan Mediterranean Sea port	Planned: 1 million bbl/d	Approximately 1,038 miles	$2.9 billion	Detailed engineering study began June 2001. Construction scheduled to begin in 2002, with completion targeted for 2004.
Baku-Supsa Pipeline (AIOC "Early Oil" Western Route)	Baku to Supsa (Georgia), terminating at Supsa Black Sea port	Currently: 100,000 bbl/d; proposed upgrades to between 300,000 bbl/d to 600,000 bbl/d	515 miles	$600 million (before upgrade)	Exports began in April 1999; approximately 90,000 bbl/d exported via this route in 2000.
Baku-Novorossiisk Pipeline (Northern Route)	Baku via Chechnya (Russia) to Novorossiisk (Russia), terminating at Novorossiisk Black Sea oil terminal	100,000 bbl/d capacity; possible upgrade to 300,000 bbl/d	868 miles; 90 miles are in Chechnya	$600 million to upgrade to 300,000 bbl/d	Exports began late 1997; exports in 2000 averaged only 10,000 bbl/d.
Baku-Novorossiisk Pipeline (Chechnya bypass, with link to Makhachkala)	Baku via Dagestan to Tikhoretsk (Russia) and terminating at Novorossiisk Black Sea oil terminal	Currently: 120,000 bbl/d (rail and pipeline: 160,000 bbl/d); Planned: 360,000 bbl/d (by 2005)	204 miles	$140 million	Completed April 2000. Eleven-mile spur connects bypass with Russia's Caspian Sea port of Makhachkala.
Caspian Pipeline Consortium (CPC) Pipeline	Tengiz oil field (Kazakhstan) to Novorossiisk Black Sea oil terminal	Currently: 565,000-bbl/d; Planned: 1.34-million bbl/d (by 2015)	990 miles	$2.5 billion for Phase 1 capacity; $4.2 billion total when completed	First tanker loaded in Novorossiisk (10/01); exports rising to 400,000 bbl/d by end-2002

Central Asia Oil Pipeline	Turkmenistan and Afghanistan to Gwadar (Pakistan)	Proposed 1 million bbl/d	1,040 miles	$2.5 billion	Memorandum of Understanding signed by the countries; project stalled by regional instability and lack of financing.
Iran-Azerbaijan Pipeline	Baku to Tabriz (Iran)	Proposed 200,000 bbl/d to 400,000 bbl/d	N/A	$500 million	Proposed by TotalFinaElf.
Iran Oil Swap Pipeline	Neka (Iran) to Tehran (Iran)	175,000 bbl/d, rising to 370,000 bbl/d	208 miles	$400 million to $500 million	Under construction; oil will be delivered to Neka and swapped for an equivalent amount at the Iranian Persian Gulf coast.
Kazakhstan-China Pipeline	Aktyubinsk (Kazakhstan) to Xinjiang (China)	Proposed 400,000 bbl/d to 800,000 bbl/d	1,800 miles	$3.0 billion to 3.5 billion	Agreement 1997; feasibility study halted in September 1999 because Kazakhstan could not commit sufficient oilflows for the next 10 years.
Kazakhstan-Turkmenistan-Iran Pipeline	Kazakhstan via Turkmenistan to Kharg Island (Iran) on Persian Gulf	Proposed 1million bbl/d	930 miles	$1.2 billion	Feasibility study by TotalFinaElf; proposed completion date by 2005.
Khashuri-Batumi Pipeline	Khashuri (Georgia) to Batumi (Georgia)	Initial 70,000 bbl/d, rising to 140,000 bbl/d-160,000 bbl/d	Rail system from Dubendi, Azerbaijan, to Khashuri, then 105-mile pipeline from Khashuri to Batumi	$70 million for pipeline renovation	ChevronTexaco has canceled plans to rebuild and expand the existing pipeline.
Trans-Caspian (Kazakhstan Twin Pipelines)	Aqtau (western Kazakhstan, on Caspian coast) to Baku; could extend to Ceyhan	N/A	370 miles to Baku	$2 billion to $4 billion (if to Ceyhan)	Feasibility study agreement signed in December 1998 by Royal/Dutch Shell, ChevronTexaco, ExxonMobil, and Kazakhstan; project stalled by lack of Caspian Sea legal agreement.

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September 2001

United Kingdom

With its significant North Sea reserves, the United Kingdom is a major European oil and natural gas producer. It is also one of the largest energy consumers in Europe.

Information contained in this report is the best available as of September 2001 and is subject to change.

BACKGROUND

The United Kingdom (official name: United Kingdom of Great Britain and Northern Ireland, abbreviated: UK) is a major political and economic world power and a close ally of the United States. It is also the world's fourth-largest economy. The country joined the European Union (EU) in 1973 (confirmed by referendum in 1975), but has no plans to join the common European currency, the euro, in the immediate future. Despite the UK's lack of participation in the euro, the country has continued to attract foreign direct investment (FDI) - about $517 billion total at the end of 2000, second in the world after the United States. The UK is an even larger exporter of capital - outward FDI at the end of 2000 totaled $902 billion, also second to the United States. The UK maintains a smaller public sector than many of its EU counterparts.

The UK, like most of the OECD, has seen growth rates decline in 2001. GDP growth in the UK is expected to decline to 2% in 2001, and will decline further still if the economy of the United States approaches a mild recession, as the UK economy is the second-closest linked to that of the United States of all the countries of the EU. This slowdown is also expected to decrease external demand, raising the trade deficit for 2001. Despite this, unemployment fell to a 26-year low in July 2001.

Given low inflation (under the government's target of 2.5% for 28 consecutive months) and the prospect of slackening growth (especially in the manufacturing sector), the Bank of England has cut interest rates four times in 2001, most recently in August.

The United Kingdom is by far the largest petroleum producer and exporter in the EU (Norway is not a member of the EU). It also is the largest producer and an important exporter of natural gas in the EU. Most of the UK's oil and gas reserves and production are located off the coast of Scotland, with the Scottish city of Aberdeen considered to be the oil and gas capital of the United Kingdom. The International Petroleum Exchange (IPE), the second-largest energy futures exchange in the world, is located in London. The second and third-largest publicly traded energy companies in the world in terms of market value, Royal Dutch/Shell and BP, respectively, are based in the UK (Royal Dutch/Shell is also based in the Netherlands). Because major UK energy companies are private, the imminent decline in British oil and gas production most likely will translate to an increase in UK companies' involvement abroad, mitigating the effect in the overall UK economy, though Scottish employment is particularly sensitive to North Sea production levels. The oil and gas industry represented about 12% of industrial capital investment, and 2% of total capital investment in 2000. The energy industry overall represents about 4% of GDP. The UK has high taxes on petroleum products, making for among the highest prices in the EU. High fuel prices caused protests and blockades in September 2000.

In July 1999, a Scottish Parliament met for the first time in almost 300 years. "Devolution" gives the Scottish Parliament the ability to tax its own citizens, plus jurisdiction over local issues such as education, health, transport, and agriculture. It has no effect on the economic and industrial structure of the United Kingdom, which remains a single market. Devolution has had no effect on North Sea oil and gas.

North Sea Oil and Gas

North Sea oil and gas reserves were first discovered in the 1960s. The North Sea did not emerge immediately as a key non-OPEC oil producing area, but North Sea production grew as major discoveries continued throughout the 1980s and into the 1990s. Although the region is a relatively high cost producer, its high quality crude oil, political stability, and proximity to major European consumer markets have allowed it to play a major role in world oil and gas markets.

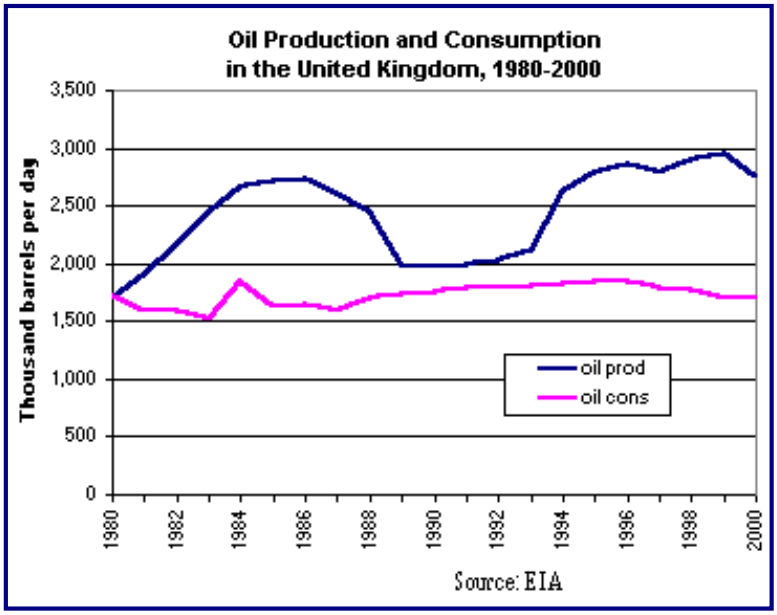
Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil. (Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field.) Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 450,000 bbl/d by 2005, but discussions are reported to be underway on building a pipeline spur from the Statfjord system to the Shell-run Brent pipeline to Sullom Voe. The increased throughput would support trade in the increasingly dated Brent price marker, extending its life as a price marker and reducing volatility in the 15-day Brent forward market, where liquidity has fallen to about 10 cargoes per delivery month compared with 300-400 deals per month in the early 1990s.

The North Sea is considered a "mature" area, with few large discoveries likely to be made. Only a few frontier areas hold the possibility of further discoveries of large oil and gas fields. In both of the major North Sea producing nations, Norway and the UK, government and industry are taking steps to restructure their oil and gas sectors to make them more internationally competitive.

OIL

The UK holds about 5 billion barrels of proven oil reserves, almost all of which is located in the North Sea. Most of the country's production comes from basins east of Scotland in the central North Sea.

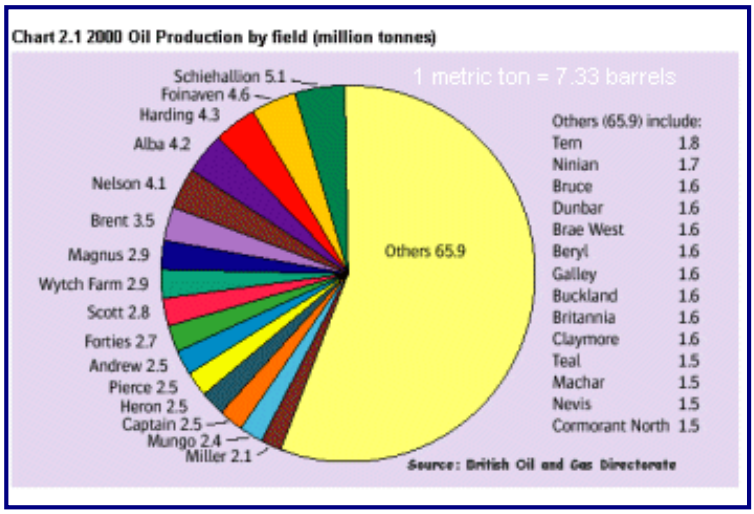
The northern North Sea (east of the Shetland Islands) also holds considerable reserves, and smaller deposits are located in the North Atlantic Ocean, west of the Shetland Islands. There are over 100 oil and gas fields currently onstream, and several hundred companies are active in the area. In 2000, the United Kingdom's production declined to 2.75 million barrels per day (bbl/d), down from a historical high of 2.95 million bbl/d in 1999. Production is expected to decline by 85,000 bbl/d in 2001. Most of the UK's crude oil production ranges in gravity from 30º to 40º API. Most high quality crude is exported, while cheaper, lower quality (mainly from the Middle East) crude oils are imported for refining. Unit costs for UK oilfields averaged just above $15 per barrel in 2000, though fields that started production in the 1990s have lower costs.



The domestic UK oil and gas industry is expected to decline as reserves are depleted in the coming decade. The British Oil and Gas Industry Task Force was set up in 1998 to bring together government departments and oil and gas industry representatives (the oil and gas industry is 100% in the hands of the private sector) to discuss the future of the industry. A successor body to the Task Force, known as "PILOT", now has been created to oversee the execution of Task Force recommendations and future developments. Government and industry are interested in collaborating to facilitate a "gentle decline" in British North Sea production, a component of which involves shifting focus from small numbers of very large projects to larger numbers of smaller projects.

Production

The number of fields under development or in production in the UK at the end of 2000 was 264. Just two fields ceased production, Bladen and Blenheim. Oil production from six offshore fields commenced in 2000: Bittern, Cook, Guillemot West, Guillemot North West, Shearwater (condensate), and Keith. In 2001, as of July, four new offshore oil fields were approved for development by the British Oil and Gas Directorate: Halley, Hannay, Kestrel, and Otter; and the Angus field was approved for redevelopment.



In December 2000, the British government gave approval to four new projects that will result in $1.5 billion in new investment in the British North Sea: (1) a £320 milliongas pipeline from the Shetland Islands to the Magnus oil field that takes suplus gas from Sullom Voe oil terminal on the Shetland Islands to be reinjected for enhanced recovery in the Magnus field; (2) a floating platform to drill for oil in the Leadon field which was discovered in 1979, but so far undeveloped, that is expected to yield 50,000 bbl/d of oil equivalent (see below); (3) further development by BP of

the Foinaven oil field; and (4) Ranger Oil's (subsidiary of Canadian Natural Resources Limited) production in the Kyle field, which started in April 2001 at 7,000 bbl/d, in addition to gas production. Total investment spending in the UK continental shelf in 2000 was about £3 billion, though continued high oil prices make it likely that investment will increase for 2001. Most new developments will be subsea, using existing infrastructure, instead of new platforms.

As noted above, production commenced in April 2000 from the Bittern, Guillermot West, and Guillermot North West fields by means of the Amerada-Hess operated Triton FPSO. About 78% of the content is British, and the three fields have reserves of about 140 million barrels of oil and 180 billion cubic feet (Bcf) of gas. Expected field life is 13 years and daily production is 60,000 bbl/d. Another development is the £350-million expansion Area B to Texaco's Captain field completed in December 2000 allows production to increase by 25,000 bbl/d to 85,000 bbl/d and will extend the field's life to beyond 2015.

Some of the smaller projects planned for the British North Sea include development of the Jade and Blake fields. In January 2000, the British subsidiary of Phillips Petroleum (operator) and its partners British Gas, Texaco, Agip, and OMV received approval from DTI to develop the Jade field. The field is expected to produce 15,000 bbl/d of crude oil and 200 million cubic feet per day (Mmcf/d) of natural gas after it comes onstream in late 2001. The BG-operated Blake field represents the opening up of the Outer Moray Firth for new discoveries and developments. It has a subsea tie-back to the existing Bleo Holm FPSO, and will extend the life of the existing Ross field. Production is expected to start in third-quarter 2001.

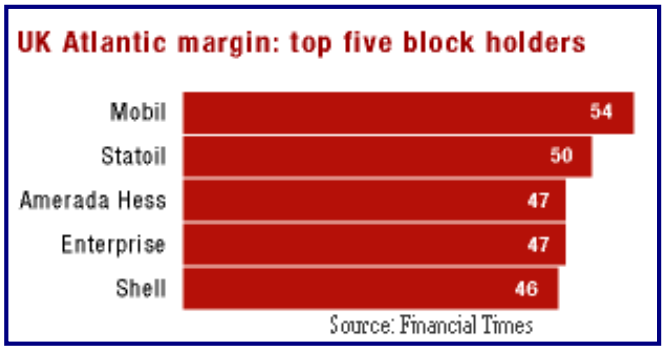
Another important development is the Skene field, which is being developed by operator ExxonMobil as a subsea tie-back to the Beryl Alpha platform. This field has a complex mix of hydrocarbons, including crude oil and condensate, that is estimated to be about 100 million barrels of oil equivalent. Only the implementation of the latest technology using a heated flowline bundle has made recovery possible. It is expected to come online in April 2002.

A larger project that was given approval in 2000 is the development of the Leadon field. It was discovered in 1979, but became economically viable with the discovery of a northern extension of the field. The Canadian company Kerr-McGee-operated field is expected to commence production in early 2002, and will peak at 40,000 bbl/d of crude oil.

Europe's largest on-shore oilfield is Wytch Farm. Estimated reserves are 500 million barrels. Egdon Exploration is active in the area, and it is hoped that even smaller fields can be economically viable as they are on-shore. Other smaller on-shore fields are clustered in east-central England.

Industry Structure

Industry reorganization that started with BP's 1998 merger with Amoco continues. The merged BP Amoco, (now simply BP) already one of the world's largest petroleum companies, announced in April 1999 its intentions to take over Los Angeles-based Atlantic Richfield (Arco), which was completed in April 2000. The merged company is truly global and is the world's third-largest publicly traded oil and gas company. Most of the majors have a share of UK North Sea production, including BP, Chevron, Conoco, ENI, ExxonMobil, Royal Dutch/Shell, Texaco, and TotalFinaElf. Amerada Hess, Enterprise, and Statoil also have large shares. The graphic shows the number of blocks held by each top-ranking company in 2000.



BP Exploration is managed from Aberdeen, Scotland (as are most other companies that are active in the British North Sea). BP produces oil and gas and brings ashore 40% of the UK's total production through the Forties Pipeline System to Grangemouth, Scotland. BP Amoco has producing fields in the North Sea and, since the end of 1997, in the North Atlantic, west of the Shetland Islands. It operates the Sullom Voe oil terminal in the Shetlands, which is Europe's largest oil terminal. The 206,000-bbl/d oil refinery and petrochemical complex at Grangemouth represents one of Scotland's largest industrial complexes.

British independent oil companies, important in the North Sea oil scene, were particularly hard hit by the oil price collapse of 1998. As a result, the major five independents at the time, Enterprise, Lasmo, Premier, British-Borneo, and Cairn, were hesitant to approve new investment and development in 1999-2000, though Enterprise has now begun more investment and development. The consolidation sweeping the oil majors has affected the independents. Enterprise, the largest British independent, unsuccessfully attempted to take over the second largest, Lasmo, in the spring of 1999. Enterprise's UK production was 164,907 barrels of oil equivalent per day in 2000. In 2000, Italian oil and gas giant ENI began to acquire British independents, British-Borneo in March 2000, and Lasmo in February 2001. This gives ENI a presence in the North Sea, and increases its worldwide oil and gas assets, particularly in Asia. Regarding the remaining two independents, Premier is heavily focused outside of the UK, and Cairn's production and reserves are very small, even for an independent.

Downstream

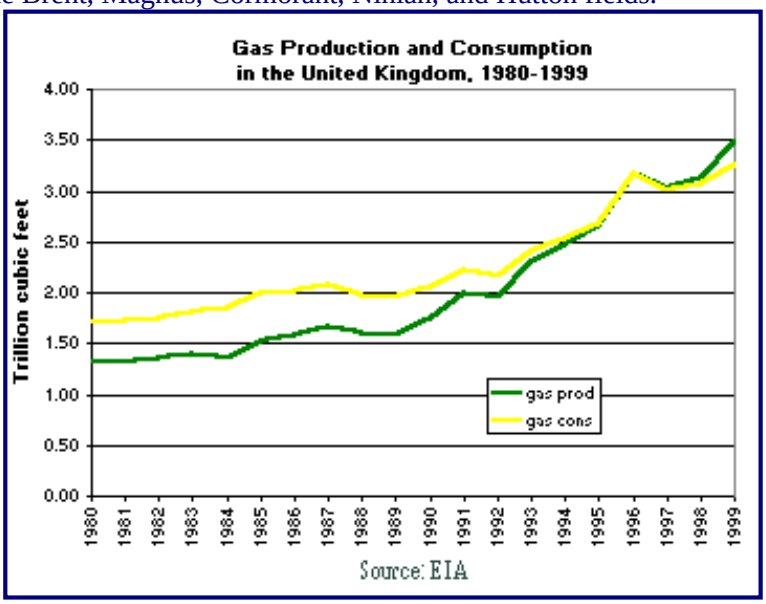
The UK's crude oil refining capacity is approximately 1.77 million barrels per day, just slightly more than the country's consumption. However, the UK imports and exports refined products because British refineries produce an excess of some grades and products and insufficient quantities of others for local demand. Additionally, demand for gasoline varies seasonally. The largest refinery is ExxonMobil's (Esso's) 311,240-bbl/d Fawley refinery in Southhampton, one of the largest in Europe and marine tanker accessible. It also has a pipeline to the on-shore Wytch Farm field. The 100,000-bbl/d Port Clarence Phillips-Imperial Petroleum refinery at North Tees is connected by pipeline to the Phillips Consortium Ekofisk Oil Terminal at Seal Sands, giving it a direct feed from the North Sea. The Grangemouth refinery is also directly connected to the North Sea through the Forties Pipeline System.

Petroleum products represented 45% of final energy consumption in 2000. The retail gasoline market is dominated by Esso (ExxonMobil), BP, Shell, TotalFinaElf, Texaco, and Conoco, which together account for 58% of gasoline sales. Supermarkets now account for 8% of retail sales. Total retail sales were 28 billion liters (7.4 billion gallons) in 2000. The transport sector consumed 74% of petroleum products in 2000, whereas the energy industry consumed just 7%. Fuel oil use has declined 30% since 1998, as industrial and home-heating demand has dropped in favor of gas.

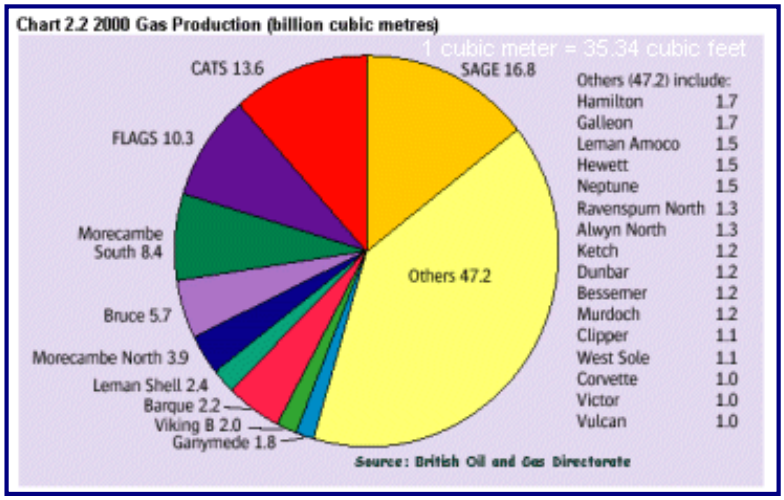
NATURAL GAS

The UK contains an estimated 26.8 trillion cubic feet (Tcf) of natural gas reserves, most of which are in non-associated gas fields located off the English coast in the Southern Gas Basin, adjacent to the Dutch North Sea sector. The UK shares the declining Frigg field with Norway (39.18% to the UK), which is expected to be shut down in 2002, and has small share of the 0.44-Tcf Statfjord field (14.53%). There are a few small fields on-shore. The Irish Sea contains the large Morecambe and Hamilton fields. Morecambe alone accounts for up to 20% of British natural gas production. Key producing gas fields in the North Sea include BP's 5.7-Tcf Leman, Chevron and Conoco's 3-Tcf Brittania, Shell's 1.7-Tcf Indefatigable and 0.8-Tcf Clipper, and TotalFinaElf's 0.85 Tcf Elgin. Key pipelines are the Scottish Area Gas Evacuation (SAGE) system to the St Fergus Terminal, which

handles gas produced from a number of North Sea fields, including Britannia, the Beryl and Brae areas, and others in the central/northern North Sea, the Central Area Transmission System (CATS) that also goes to the Central North Sea, and takes gas from several fields, including Everest, Judy, and Jade, and others, and the Far North Liquids and Associated Gas System (FLAGS) that takes gas from the northern North Sea, including the Brent, Magnus, Cormorant, Ninian, and Hutton fields.



The largest project to come online in 2001 (in March) in the British North Sea is the TotalFinaElf-operated Elgin/Franklin platform, which might prove to be the last big North Sea production platform. It is the world's largest high-pressure, high temperature development. The Elgin/Franklin platform has extensive processing facilities, unlike most North Sea platforms. The $2.3-billion platform is expected to last for 22 years in its location in the central North Sea, in the Graben area, off the coast of Scotland. It is to produce 700 million barrels of oil equivalent, about half condensate and half natural gas. This equates to peak production of 350 million cubic feet per day (Mmcf/d) of natural gas. The export pipelines are shared with the Shearwater field, and include a 294-mile gas pipeline to Bacton and a 24-mile condensate pipeline to the Marnock platform. The Shell-operated Shearwater field in the central North Sea was inaugurated in September 2000, and has reserves of 0.71 Tcf natural gas and 110 million barrels of condensate. Gas production is expected to peak at 375 Mmcf/d.



The Brigantine cluster is the most important recent development in the Southern Gas Basin. It is three fields with two platforms using extended reach horizontal wells to get at reserves of 0.27 Tcf. Shell is the operator, and production of 130 Mmcf/d commenced in the first quarter of 2001. There is a 12-mile pipeline to the Corvette platform, which is connected indirectly with Bacton.

British Gas was the monopoly supplier to the interruptible market until the passage of the 1995 Gas Act, which split the company into supply and shipping (British Gas Trading Limited) and while other functions remained with British Gas, including transport subsidiary Transco. In 1997, Centrica was demerged from from British Gas, and British Gas was renamed BG. Centrica is the holding company for British Gas Trading, British Gas Services, the Retail Energy Centers, and is the producer in the Morecambe fields. BG retained Transco, along with exploration and production, international downstream, R&D and properties. In October 2000, BG again split, with Transco becoming part of a separate holding company Lattice Group. Independent Gas suppliers entered the firm (non-tariff) market in 1990, but the larger interruptible market (smaller customers) brought in competition in 1995. The consumer gas market was deregulated by region from October 1997 to June 1998, such that all residential and commercial customers could choose their supplier at the end of this process. At the end of 2000, suppliers other than British Gas Trading had captured 20-30% of the market in many

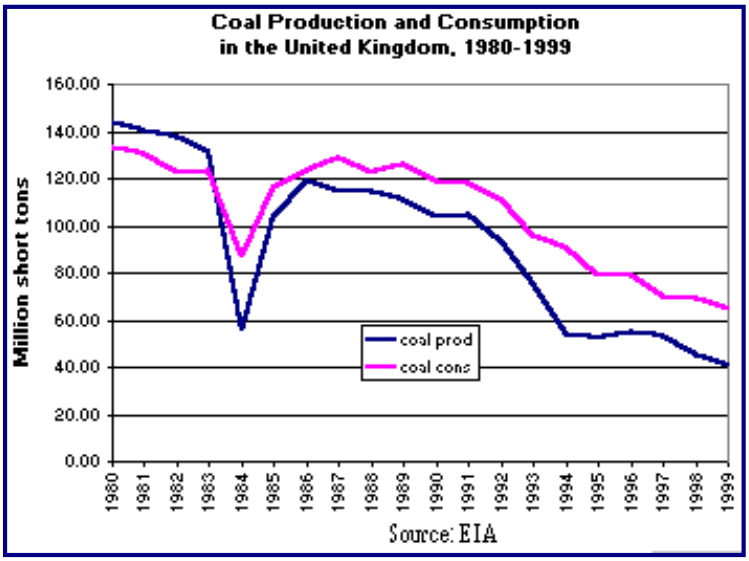
regions of the UK. In July 2001, Houston-based Dynegy purchased BG Storage from what remains of BG for $590 million, acquiring gas production wells and platforms, salt caverns, pipelines, and a natural gas processing terminal.

The UK's gas and electricity regulatory body is the Office of Gas and Electricity Markets (Ofgem). Ofgem has proposed reforming price controls on Transco's pipeline usage fees. The privatization of the UK's gas industry, leading to an increased gas supply and reduced prices, has helped gas to replace much of the UK's reliance on coal as a source for electricity generation. The natural gas share of utility fuels was 1% in 1988 and is expected to increase to almost 50% by 2010. Privatization in the UK has progressed well in advance of EU requirements.

In 1998, the UK-Continent Gas Interconnector pipeline was opened, with terminals at Bacton, England and Zeebrugge, Belgium. This is the first natural gas pipeline linking the United Kingdom to the European continent. A new pipeline to connect Ireland to Scottish gas sources in the Corrib field was approved in November 1999, and a plan to connect Ireland to England via Wales was announced in April 2000. A pipeline would run from Manchester, England, underground to Wales, and then under the Irish Sea to just north of Dublin. There is currently one pipeline linking Britain and Ireland, connecting Ireland to Scottish gas sources. Despite these pipeline projects, the UK will remain a much smaller natural gas exporter than North Sea neighbor Norway, and will eventually become a net importer as the UK begins to import Norwegian gas again. Norway had once supplied up to a quarter of British demand in the 1980s, but this dwindled as the Frigg field that supplied the gas was depleted. The new Vesterled gas pipeline, set to begin operations October 1, 2001, will be one of the ways Norwegian gas may enter the UK. Vesterled will connect the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gasfields, and from there to other areas of the Norwegian North Sea such as the Ormen Lange gasfield that is scheduled to come on stream in 2006. In July 2001, BP announced a 15-year contract to buy 56.5 billion cubic feet (Bcf) natural gas per year from Statoil. However, Statoil has indicated that it would not import large volumes of gas through Vesterled unless Britain changed its pricing system for bringing gas onshore from North Sea fields. Statoil officials have asserted that the UK's system of auctioning entry capacity, or access rights to the national pipeline system, had produced volatile, very high prices.

COAL

Coal production and consumption in the United Kingdom have decreased dramatically since 1986. UK coal production fell from 119 million short tons (Mmst) in 1986 to 40.9 Mmst in 1999. Production fell again in 2000, but demand rose, increasing imports. In 2000, steam coal accounted for 80% of coal demand, coking coal for 15%, and anthracite for 5%. Electricity demand accounted for 95% of demand for steam coal and 46.5% of demand for anthracite. In the late 1980s, coal accounted for about two-thirds of the United Kingdom's thermal electricity production. Currently, less than half of UK thermal electricity is coal-fired, and the figure is expected to fall below one-third by the end of the decade. Coal mines are located primarily in central and northern England and southern Wales, with some coal mines also found in southern Scotland. The UK produced 40.5 million tons of bituminous coal and 409 thousand tons of anthracite coal in 1999. The UK also produces coke-oven coke in quantities such that it is self-sufficient. Nevertheless, net imports of coal in 1999 were 23.9 million tons.



Between 1984 and 1985, the British coal miners' union staged a year-long strike. The strike dramatically altered energy production and consumption patterns in the United Kingdom for that year and precipitated the longer term decline of the industry (see graph). Employment in the industry has plummeted since the late 1980s. The United Kingdom began liberalizing its electricity market in 1989, and this liberalization is one of the major reasons for the decline of the country's coal industry. Prior to the privatization of electricity, the cost of domestic coal to electric utilities had far exceeded the cost of coal traded in international markets. The Central Electricity Generation Board (CEGB) had been the primary purchaser of British coal. The CEGB largely subsidized the British coal industry, purchasing domestic coal at above world market prices and then passing on those costs to consumers. This ended when National Power and PowerGen, two private electricity generation companies, were formed in the early 1990s, weakening the bargaining power of British Coal, the national coal company.

In 1992, the British coal industry reached a turning point. Growing competition from increasingly available natural gas, the imminent removal of the regional electricity companies' captive franchise supply markets, and newly-enacted pollution abatement goals all worked to initiate the steady decline of the industry. The industry was privatized in 1994, at which point RJB Mining bought the major British Coal assets and become the country's major producer. Mining Scotland and Celtic Energy are the other two remaining companies. The UK coal industry had not received any subsidies since 1995, but in November 2000 the European Commission approved a modernization plan and aid scheme. The aid would go toward mines/production units that have long-term economic viability on the world market, but are having temporary difficulties as they restructure in an effort to reduce production costs. The total amount of aid will not exceed £110 million, and two disbursements of £25 million and £21 million have been made so far. Production costs over the period 1992 to 1999 already fell 35%, and the expectation is that these costs can fall further still before the aid scheme expires in July 2002.

New EU environmental directives are expected to further increase British coal production costs, leading some analysts to predict an end to the United Kingdom's coal industry in the early 2000s. RJB Mining is more optimistic about the future of British coal. RJB maintains that foreign coal prices will increase, making British coal more competitive, and that clean coal technology will allow power stations to burn increased amounts of coal without increased greenhouse gas emissions. Higher natural gas prices, gas-fired power plant outages for maintenance and repair, and reduced nuclear power led to a 14% increase in coal consumption by power producers in 2000.

ELECTRICITY

The United Kingdom has 70 million kilowatts of installed electric capacity, about 80% of which is thermal, 18% nuclear, and 2% hydropower. The country generated 342.8 billion kilowatt hours (bkwh) of electricity in 1999, making it the third-largest electricity market in Europe (behind Germany and France).

Electricity privatization began in the early 1990s, and the final phase of transition ended in May 1999. Initially, all non-nuclear state-owned power stations were privatized and four major generating companies -- PowerGen and National Power in England and Wales, and ScottishPower and Hydro-Electric in Scotland -- were formed to operate the stations. The grid distribution system in England and Wales became the property of the National Grid Company. Regional Electricity Boards were

privatized as separate distribution companies. Large customers were the first to be able to choose their suppliers, with all small customers (below 100 kW peak load) being able to choose by May 1999.

The number of electric generation companies in the United Kingdom has increased to 27 as a result of the liberalization process, according to DTI, such that 40% of the UK's electricity was generated by these new companies in 2000. In March 2001, the structure of the electricity industry changed yet again. Under the former system, generators and suppliers in England and Wales traded electricity through the electricity pool, which was regulated by the National Grid Company, owner of the transmission network. The New Electricity Trading Arrangements (NETA) changed this to a system based on bilateral trading between generators, suppliers, traders, and customers. The system includes fowards and futures markets, a balancing mechanism to enable the National Grid Company to balance the system, and a settlement process. Dallas-based TXU purchased United Utilities' retail electricity and natural gas business, Norweb Energi, for $465 million in August 2000. This, added to TXU's European retail business Eastern Energy, creates the UK's largest electricity retailer, with over 5.6 million customers. Powergen, with 2.6 million retail customers as well as 14% of electricity generation in England and Wales, merged with Louisville-based LG&E Energy in December 2000.

In Scotland, the two main companies, Scottish Power and Scottish and Southern Energy, cover the full range of electricity provision. Ofgem has made proposals to further reform the Scottish power market. Northern Ireland, part of the United Kingdom but not part of Great Britain, is served by Northern Ireland Electricity, one of the largest companies in Northern Ireland and part of the Viridian Group. Northern Ireland has a separate electricity and gas regulatory body, Ofreg. The grids of Northern Ireland and the Republic of Ireland are connected for electricity import/export.

Nuclear

In 1995, the government announced that it would privatize its more modern nuclear stations while retaining ownership of older stations. In 1996, more modern stations were privatized and British Energy became the holding company of Nuclear Electric and Scottish Nuclear, which merged in 1998 to form British Energy Generation, the nation's largest private nuclear generator and the world's first wholly privatized nuclear utility. British Energy operates eight nuclear power stations in the UK (as well as several in the U.S. through its AmerGen subsidiary that is jointly owned with PECO). Each station consists of two advanced gas-cooled reactors, except Sizewell B, which is a modern pressurized-water reactor. Nuclear power stations were not privatized simultaneously with non-nuclear stations. No new plants have been built since 1995, but because of limited domestic coal and gas reserves in the long run, new construction is under discussion, at least to maintain nuclear's market share as older nuclear plants are retired. Of the UK's 33 reactors, 26 are of the old Magnox design. Six of the Magnox reactors are being decommissioned, as well as the Dounreay prototype fast reactor. The remaining Magnox plants are run by the state-owned British Nuclear Fuels. British Nuclear Fuels operates the Sellafield reprocessing plant, and is one of only two companies in the world that provides reprocessing and recycling technologies. The British nuclear industry is regulated by the Department of Trade and Industry's Nuclear Directorate.

ENVIRONMENT

With a reduction in sulfur dioxide and carbon dioxide emissions, environmental conditions in the United Kingdom have improved over the past couple of decades. Some of these environmental improvements, such as a reduction in air pollution, can be attributed to the United Kingdom's energy use choices. Partially as a result of deregulation and the elimination of coal subsidies, coal's share of total primary energy consumption is gradually being replaced by natural gas.

Improvements in energy efficiency have led to a gradual reduction in both energy and carbon intensity. In 1980, energy intensity in the United Kingdom registered 11.70 thousand Btu per $1990, decreasing to 8.37 thousand Btu per $1990 in 1999, a 27% decline. Similarly, carbon intensity in 1999 registered 0.13 metric tons of carbon per thousand $1990, a 45% decrease from 1980 levels. Per capita energy consumption, at 167.8 million Btu in 1999, is rising gradually.

As the United Kingdom enters the 21st century, many energy and environment-related policies reflect the country's awareness of climate change issues. With introduction of the Climate Change Levy in 2001, and its exemption for renewable energy resources like solar and wind, these alternative sources of energy are beginning to gain more attention. For example, the United Kingdom hopes to increase the share of electricity generated by renewables from the current 2%, to 10% by 2010.

Sources for this report include: Aberdeen Press & Journal; CIA World Factbook; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Hart's European Offshore Petroleum Newsletter; Oil & Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; The Scotsman; U.K. Department of Trade and Industry; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

Head of State: Queen Elizabeth II
Prime Minister: Anthony (Tony) Blair, re-elected June 2001
Population (2000E): 59.5 million
Location/Size: Western Europe, islands including the northern one-sixth of the island of Ireland between the North Atlantic Ocean and the North Sea, northwest of France/244,820 sq km (slightly smaller than Oregon)
Capital City: London
Language: English
Ethnic groups: English 81.5%, Scottish 9.6%, Irish 2.4%, Welsh 1.9%, Ulster 1.8%, West Indian, Indian, Pakistani, and other 2.8%
Religions: Anglican 27 million, Roman Catholic 9 million, Muslim 1 million, Presbyterian 800,000, Methodist 760,000, Sikh 400,000, Hindu 350,000, Jewish 300,000 (1991 est.)
Defense (8/98): Army, 113,900; Navy, 44,500; Air Force, 52,540

ECONOMIC OVERVIEW

Chancellor of the Exchequer: Gordon Brown
Currency: Pound sterling
Exchange Rate (9/04/01): 1 US Dollar = 0.69 pounds
Gross Domestic Product (GDP, 2000E): $1,415 billion
Real GDP Growth Rate (2000E): 3.0% **(2001F):** 2.0%
Inflation Rate (consumer prices, 2000E): 2.9% **(2001F):** 2.0%
Unemployment Rate (2000E): 3.7% **(2001F):** 3.4%
Merchandise Exports (2000E): $283 billion
Merchandise Imports (1999E): $327 billion
Major Trading Partners: United States, Germany, France, Netherlands
Major Exports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment
Major Imports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

ENERGY PROFILE

Secretary of State for Trade and Industry: Patricia Hewitt
Minister of State for Industry and Energy: Brian Wilson
Proven Oil Reserves (1/1/01): 5 billion barrels
Oil Production (2000): 2.75 million bbl/d, of which 2.48 million bbl/d was crude oil
Oil Consumption (2000): 1.7 million bbl/d
Crude Oil Refining Capacity (1/1/01): 1.77 million bbl/d
Net Oil Exports (2000): 1.05 million bbl/d
Natural Gas Reserves (1/1/01): 26.8 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 3.49 Tcf

Natural Gas Consumption (1999E):3.26 Tcf
Natural Gas Net Exports (1999E): 0.02 Tcf
Major Systems: Brent, Ninian, Forties, Flotta, Fulmar
Major Fields: E. Brae, Brent, Forties, Magnus, Miller, Scott
Oil and Gas Companies: Amerada Hess, BP Amoco, BHP, Chevron, ExxonMobil, Kerr-McGee, Phillips, Ranger Oil, Shell, Texaco
Recoverable Coal Reserves (12/31/96E): 1.65 billion short tons
Coal Production (1999E): 40.9 million short tons (Mmst)
Coal Consumption (1999E): 64.8 Mmst
Electrical Generation Capacity (1/1/99): 69.9 gigawatts (79.7% thermal, 2.1% hydro, 18% nuclear, 0.2% other)
Electricity Generation (1999E): 342.8 billion kilowatt hours (bkwh)
Electricity Consumption (1999E): 333 bkwh

ENVIRONMENTAL OVERVIEW

Secretary of State for the Environment, Food, and Rural Affairs: Margaret Beckett
Total Energy Consumption (1999E): 9.9 quadrillion Btu* (2.6% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 152.4 million metric tons of carbon (2.5% of world carbon emissions)
Per Capita Energy Consumption (1999E): 167.8 million Btu (vs. U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 2.6 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 8,365 Btu/$1990 (vs U.S. value of 12,638 Btu/$1990)**
Carbon Intensity (1999E): 0.13 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (37.0%), Residential (25.4%), Transportation (26.1%), Commercial (11.5%)
Sectoral Share of Carbon Emissions (1998E): Industrial (33.7%), Transportation (31.3%), Residential (24.3%), Commercial (10.6%),
Fuel Share of Energy Consumption (1999E): Oil (35.0%), Natural Gas (34.9%), Coal (15.7%)
Fuel Share of Carbon Emissions (1999E): Oil (41.2%), Natural Gas (33.4%), Coal (25.5%)
Renewable Energy Consumption (1998E): 137 trillion Btu* (15% increase from 1997)
Number of People per Motor Vehicle (1998): 2.3 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change. Under the negotiated Kyoto Protocol (signed on April 29th, 1998 - not yet ratified), the UK has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Sulfur dioxide emissions from power plants contribute to air pollution; some rivers polluted by agricultural wastes and coastal waters polluted because of large-scale disposal of sewage at sea.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Links

For more EIA information on the United Kingdom:
EIA - Country Information on the United Kingdom
Electricity Restructuring and Privatization in the United Kingdom

Links to other U.S. Government sites:
CIA World Factbook - United Kingdom
U.S. State Department Country Commercial Guides: Europe
U.S. State Department Consular Information Sheet
U.S. Geological Survey, map of the United Kingdom including oil fields

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July 2002

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Kazakhstan

Kazakhstan is important to world energy markets because it has significant oil and natural gas reserves. As foreign investment pours into the country's oil and natural gas sectors, the landlocked Central Asian state is beginning to realize its enormous production potential. With sufficient export options, Kazakhstan could become one of the world's largest oil producers and exporters in the next decade.

Note: Information contained in this report is the best available as of July 2002 and is subject to change.

GENERAL BACKGROUN

Kazakhstan, the largest of the former Soviet Central Asian republics, emerged as an independent country

following the 1991 collapse of the Soviet Union. Following several years of economic contraction in the early 1990's, Kazakhstan, which is heavily dependent on oil revenues, posted its first economic growth in 1996-1997, only to fall into recession again in 1998 due to the effects of the August 1998 financial crisis in Russia and slumping world oil prices. However, the recovery of world oil prices in 1999-2000, combined with a well-timed devaluation of the country's currency, the *tenge*, pulled the economy out of recession.

Kazakhstan has experienced impressive economic growth over the past three years, buoyed by increased oil exports, as well as by prudent fiscal policies and economic initiatives that were instituted in 1999. The results included a sharp reduction of inflation, which dropped to just 6.6% in 2001, a budget surplus, a stable currency, and a decreasing unemployment rate (3.3% in 2001). After posting moderate growth of 2.7% in 1999 as a whole, Kazakhstan's real gross domestic product (GDP) rose 9.8% in 2000, which was three times higher than the official government projection at the beginning of the year.

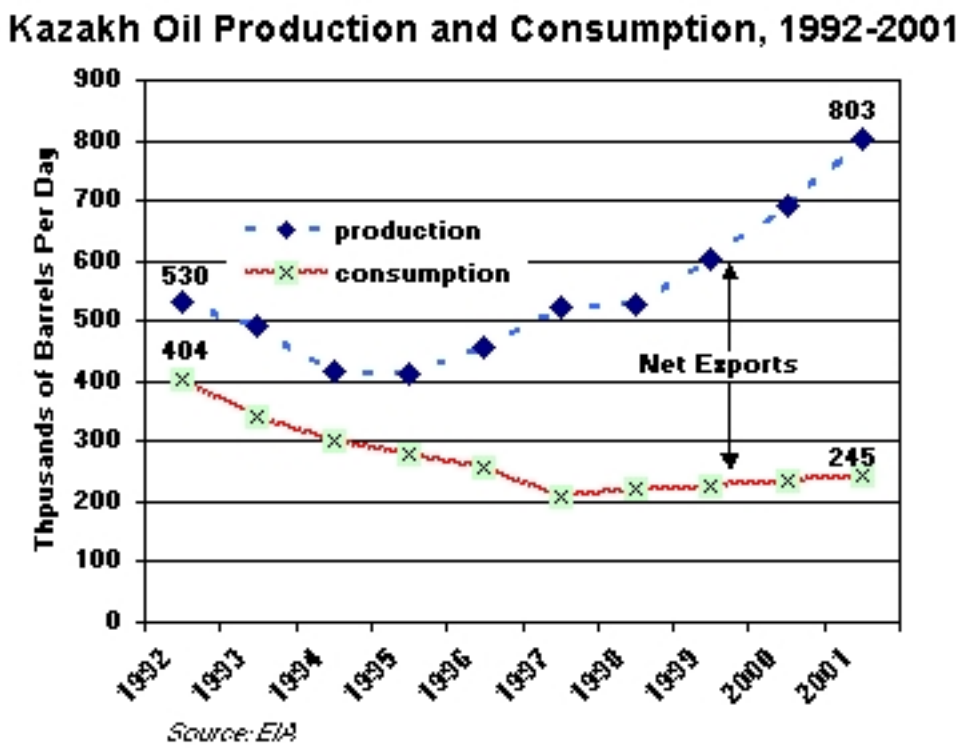
In 2001, Kazakhstan built on the previous year's economic performance by increasing its real GDP by an additional 13.2%, easily the country's best year of economic performance since independence. Kazakhstan's real GDP is expected to increase an additional 7% in 2002. The main driver behind Kazakhstan's economic growth has been foreign investment, mainly in the country's booming oil and natural gas industries. Since independence from Soviet rule in 1991, Kazakhstan has received approximately $13 billion in foreign investment in its oil and natural gas industries. According to Kazakh Minister of Economy and Trade Zhaksibek Kulekeyev, the oil industry currently accounts for approximately 30% of Kazakhstan's government budget revenue, and oil accounts for half of Kazakhstan's exports.

In January 2001, Kazakh President Nursultan Nazarbayev issued a decree establishing the National Fund to make the country less exposed to changing prices for energy and commodities exports. The National Fund, which

received $660 million from U.S. oil major Chevron (now ChevronTexaco) in exchange for Kazakhstan's 5% stake in a joint venture at the giant Tengiz oil field, will be replenished with extra budget revenues, taxes from oil companies, and signing bonuses and royalties paid by foreign partners in joint ventures.

In February 2002, President Nazarbayev decreed the formation of Kazmunaigaz, a new national oil and natural gas company. According to Kazakh officials, the main aim of establishing Kazmunaigaz, which was formed through the merger of state oil company Kazakhoil and the national oil and gas transportation firm TransNefteGaz, is to ensure a single state policy on using the country's mineral resources. Kazakhstan also is looking to its new national energy company to compete with foreign energy companies as the massive untapped oil and natural gas reserves in the Kazakh sector of the Caspian Sea begin to be exploited.

OIL



After Russia, Kazakhstan was the second largest oil-producing republic in the former Soviet Union at the time of its collapse, with production of over half a million barrels per day (bbl/d) in 1991. Kazakhstan has significant petroleum reserves, with proven reserves estimated at 5.4 billion barrels of oil. In addition, Kazakhstan's possible hydrocarbon reserves, both onshore and offshore, dwarf its proven reserves, with estimated possible reserves--mostly in the Kazakh sector of the

Caspian Sea--of between 30 billion and 50 billion barrels. Kazakh officials have said that the offshore Kashagan field alone may contain up to 50 billion barrels of oil.

Following its independence in 1991 Kazakhstan opened up its oil sector to investment and development by foreign energy companies. International projects have taken the form of joint ventures with Kazakhoil (now Kazmunaigaz), the national oil company, as well as production-sharing agreements (PSAs), and exploration/field concessions. Although Kazakhstan's oil production dropped to just 415,000 bbl/d in the first few years after the collapse of the Soviet Union, the massive level of foreign investment into Kazakhstan's oil sector over the past 11 years has helped the country boost its oil production from 530,000 bbl/d in 1992 to 811,000 bbl/d in 2001.

Kazakhstan's oil production has doubled in just the past six years. Output has been increasing by approximately 15% per year since 1998, and the country is expected to produce over 900,000 bbl/d in 2002. From January 2002 through May 2002, Kazakh production of oil and gas condensate totaled 18.52 million tons (892,600 bbl/d), a 12.4% increase from the same time period in 2001. In addition, with a number of major oil fields recently coming onstream, including North Buzachi, Sazankurak, Saztobe, Chinarevskoye, and Airankol, and fields such as Alibekmola, Urikhtau, and Kozhasai set to begin producing shortly, Kazakhstan will increase its oil production significantly in the next decade. Kazakh oil production is expected to reach 1.2 million bbl/d in 2005, 2 million bbl/d by 2010, and as much as 2.5 million bbl/d by 2015.

Most of this growth will come from three enormous fields: Tengiz, Karachaganak, and Kashagan. The Tengiz field, with six to nine billion barrels of estimated oil reserves, is being developed by the Tengizchevroil joint venture. In April 1993, Chevron (now ChevronTexaco) concluded a $20 billion agreement with the Kazakh government to form the Tengizchevroil joint venture to develop the Tengiz field. Production at the field has increased from 25,000 bbl/d in 1993 to slightly over 250,000 bbl/d in mid-2002.

ChevronTexaco plans to invest $3 billion over the next three years to expand TCO's production capacity. Tengizchevroil is expected to increase production to 400,000 bbl/d by 2005 and, given adequate export outlets, the joint venture could reach peak production of 750,000 bbl/d by 2010.

The Karachaganak field, which is being developed by Karachaganak Integrated Organization (KIO), a consortium led by Britain's BG and Agip (Italy), has estimated reserves of 2.3 billion barrels of oil and gas condensate, as well as 16 trillion cubic feet (Tcf) of natural gas. In 1997, KIO signed an $8 billion production sharing agreement to develop the Karachaganak field for 40 years, with a planned investment of $4 billion by 2006. Thus far, the development program has focused on producing gas condensate; in the first five months of 2002, the Karachaganak field was producing 99,685 bbl/d of liquid hydrocarbons, with production scheduled to increase to between 180,000 bbl/d and 240,000 bbl/d of condensate annually during the next two years.

Although work on the offshore Kashagan field is still in the exploration stage, preliminary drilling results indicate that the field is huge, and analysts have been hailing the field as the largest oil discovery in the world in the past 30 years. In February 2001, Italy's ENI, Agip's parent company, won a fiercely contested battle among partners in the Offshore Kazakhstan International Operating Company (OKIOC) to be the operator for the field. OKIOC was subsequently renamed the Agip Kazakhstan North Caspian Operating Company (Agip KCO).

In March 2001, Agip KCO discovered oil in Kashagan West 1, a well located 25 miles from the first well drilled (Kashagan East 1). Although Agip KCO released estimates in June 2002 that the Kashagan field holds between seven and nine billion barrels of crude in proven reserves, as well as 38 billion barrels in probable reserves, both Kazakh officials and energy analysts have called that estimate "conservative." Output at the first stage of development, planned for 2005, is expected to be 100,000 bbl/d, and further development

likely will catapult Kazakhstan into the top five oil producers in the world. However, Kazakhstan needs to resolve two major issues--Caspian ownership rights and export routes--before it can reach its full oil-producing potential.

Caspian Sea Issues

According to Kazakh Prime Minister Imangali Tasmagambetov, up to $120 billion could be invested in Kazakhstan's sector of the Caspian Sea over the next 10 years. Development of the offshore potential of Kazakhstan in the Caspian Sea has been slowed, however, by the ongoing dispute among the littoral states over ownership rights. This disagreement ties in with a broader debate between the Caspian Sea states over how the sea should be treated under international law and how to protect its fragile environment while exploiting its oil and natural gas resources.

Kazakhstan already has signed bilateral agreements with Turkmenistan, Azerbaijan, and Russia, pledging to divide their sections of the Caspian along median lines. However, in July 2001, an Iranian gunship forced a British Petroleum (BP) exploration vessel out of waters claimed by Iran but licensed to BP by Azerbaijan, heightening tensions and highlighting the need for a multilateral agreement. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status. Nevertheless, Kazakhstan and Russia recently agreed on a plan to develop jointly the disputed Kurmangazy field, and Kazakhstan is proceeding with development of its sector of the Caspian.

Oil Exports

The other major issue is the development of export routes to bring landlocked Kazakh oil to world markets. During the Soviet era, Kazakhstan's oil pipelines were integrated with Russia's, and all of Kazakhstan's oil was exported through the Russian pipeline system. Kazakhstan's net oil exports rose to 631,000 bbl/d in 2001, but the country's remoteness from world markets, along with its lack of export pipelines, has hindered the further growth of exports. In 2001, the majority of Kazakh oil exports was shipped by pipeline,

mainly via the Atyrau-Samara pipeline through Russia, with additional supplies shipped by rail and by barge across the Caspian Sea.

Kazakhstan took a major step towards increasing its oil exporting potential in March 2001 with the launch of the 990-mile Caspian Pipeline Consortium (CPC) pipeline. The $2.5 billion, 1.34 million-bbl/d-capacity pipeline will allow Kazakhstan to pipe its oil directly from the Tengiz field to Russia's Black Sea port of Novorossiisk. The first oil from the pipeline was scheduled to be loaded in June 2001, but several customs problems and technical hitches caused delays. After Russia and Kazakhstan reached agreement on transit tariffs for the pipeline, the first crude oil was loaded onto a tanker in Novorossiisk on October 15, 2001, and the pipeline was officially opened on November 27, 2001.

In addition to the CPC pipeline, several additional oil export pipeline routes from the Caspian Sea region are under consideration or in development. Kazakh President Nursultan Nazarbayev has expressed support for the Baku-Ceyhan Main Export Pipeline, but the country has not officially pledged to use the pipeline, preferring to keep its export options open. Kazakhstan and Iran have begun oil swaps and discussed a pipeline connecting the two countries, and in June 2002 Kazakhstan and Russia signed a 15-year oil transit agreement under which Kazakhstan will export at least 350,000 bbl/d of oil annually via the Russian pipeline system.

Downstream/Refining

Kazakhstan has three major oil refineries supplying the northern region (at Pavlodar), western region (at Atyrau), and southern region (at Shymkent), with total refining capacity of 427,000 bbl/d. The refinery at Pavlodar is supplied mainly by a crude oil pipeline from western Siberia (since Russian reserves are well placed geographically to serve that refinery), the Atyrau refinery runs solely on domestic crude from northwest Kazakhstan, and the Shymkent refinery currently uses oil from Kazakh fields at Kumkol, Aktyubinsk, and Makatinsk, although it is linked by pipeline to Russia.

In January 2002, Kazakhstan gave the Marubeni Corporation, in collaboration with the Japan Gas Corporation, the go-ahead to carry out modernization work at the Atyrau oil refinery. Marubeni already has carried out a feasibility study for the project under an understanding signed with the Kazakhstan government in May 1998 and financed by the Japan Bank for International Cooperation. No timetable has been set yet for the renovation.

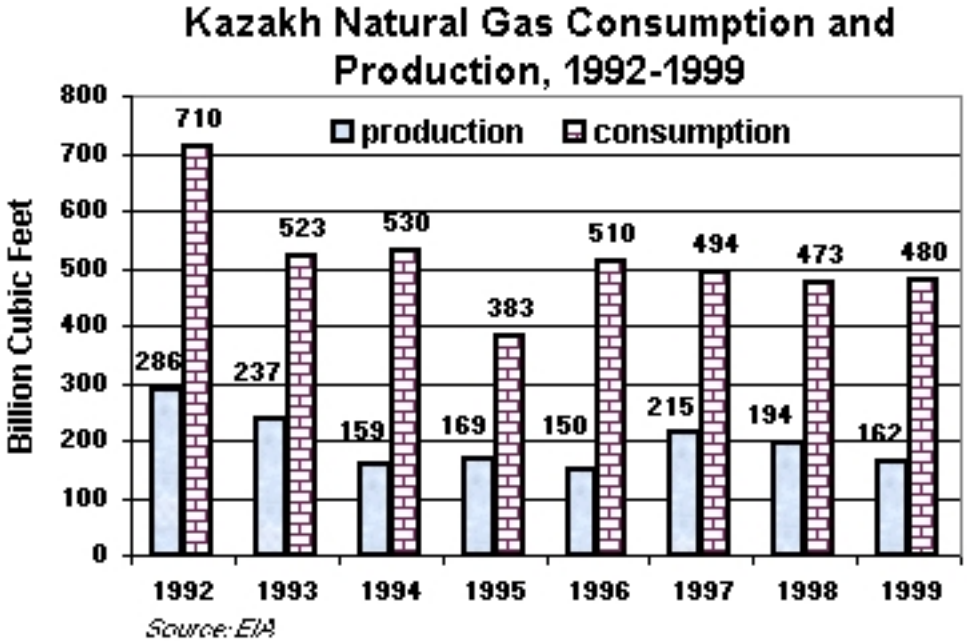
In the first two months of 2002, Kazakhstan's refineries processed 1.19 million tons of oil (an average of approximately 143,388 bbl/d), up 2.9% from the same time period in 2001. The Pavlodar refinery processed an average of 38,353 bbl/d (a 28.4% year-on-year increase), the Atyrau refinery handled 27,316 bbl/d (down 29.2%), and the Shymkent facility refined approximately 78,104 bbl/d (a 9.6% year-on-year increase). The three refineries produced 30,075 bbl/d of gasoline (an increase of 15.2% year-on-year) during this period, 40,739 bbl/d of diesel fuel (a 12% increase), and 34,955 bbl/d of fuel oil (a 14.4% decrease year-on-year).

NATURAL GAS

Kazakhstan has proven reserves of 65 trillion cubic feet (Tcf) of natural gas, ranking it in the top 20 countries in the world in terms of natural gas reserves. However, the country's natural gas industry is significantly underdeveloped, and the sector's further development is hampered by a lack of infrastructure. Kazakhstan's natural gas deposits are mainly located in the western part of the country, while the potential consuming areas are in the south and north. The lack of internal pipelines connecting the country's natural gas-producing areas to the industrial belt between Almaty and Shymkent has hampered Kazakh natural gas production, with many oil producers flaring the natural gas instead of using it.

More than 40% of Kazakhstan's proven natural gas reserves are located in one field, the giant Karachaganak field in the northwest near the border with Russia. Kazakhstan's other significant natural gas deposits include the Tengiz, Zhanazhol, and Uritau fields, and many of the undeveloped offshore areas--including the massive Kashagan field--also are believed to hold large amounts

of natural gas. Although the international consortium developing Karachaganak has concentrated mainly on producing gas condensate thus far, the field yielded 132 Bcf of natural gas in 2001. Through the first five months of 2002, the Karachaganak Integrated Organization extracted an additional 68.8 Bcf of natural gas from the field.



In order to remove disincentives to the development of the country's natural gas industry, in August 1999 the Kazakh government passed a law requiring subsoil users (such as oil companies) to include natural gas utilization projects in their development plans. As a result, in 2000, Kazakhstan increased its natural gas production to 314 billion cubic feet (Bcf), the highest level in the past decade. According to preliminary 2001 figures, Kazakhstan produced 324 Bcf of natural gas in 2001, a 3.1% increase over 2000. From January 2002 through May 2002, Kazakh natural gas production totaled 158.5 Bcf, a 2.1% year-on-year increase from the same time period in 2001.

Natural Gas Distribution

Kazmunaigaz, the new state oil and natural gas company, is now the operator of Kazakhstan's main natural gas pipelines. The company, which took over the assets of KazTransGaz when it was created in February 2002, owns over 5,400 miles of trunk pipelines, as well as 26 compressor stations with 308 gas transportation units. Since Kazakhstan is such a large, sparsely populated country, it has two separate domestic natural gas distribution networks, in the west and in the south.

However, due to the lack of a pipeline linking the natural gas fields in the western part of the country to consumers in the south, the southern areas of Kazakhstan are almost completely dependent on imported supplies. Although Kazakhstan is considering the construction of an internal pipeline to link its natural gas-producing and consuming areas, the prohibitive cost (at least $1 billion) of such a pipeline has delayed any decision to go ahead with the project.

Kazakhstan invested around $120 million to upgrade its natural gas pipeline network in 2001, including about $10 million in meters for regional systems, regular maintenance, personnel training, and new equipment. KazTransGaz began restoration work on the southern natural gas pipeline system in 2001, including repairing 24 miles of pipelines and modernizing 23 wells at the Poltoraskoye underground natural gas storage facility.

Natural Gas Imports

With 2000 natural gas consumption of 491 Bcf, Kazakhstan currently imports around 35% of its natural gas needs, mainly from Uzbekistan, but with a small amount from Russia as well. The southern region of the country--from Shymkent to the former capital of Almaty--receives its natural gas supplies from Uzbekistan via the Tashkent-Bishkek-Almaty pipeline. This pipeline snakes through Uzbekistan before reaching Shymkent, then transits Kyrgyzstan and terminates in Almaty.

Kazakhstan's dependence on imported natural gas for its southern regions has been problematic during the past two winters, when erratic pricing and supplies from Uzbekistan, combined with illegal tapping of the pipeline by Kyrgyzstan, resulted in significant supply disruptions to Almaty in the middle of the heating season. As a result, Kazakhstan is dermined to end its dependence on imported supplies for its southern regions.

Kazakhstan is pinning its hopes on the development of the Amangeldy and other gasfields in southern Kazakhstan. The Amangeldy and nearby Ayrykty fields in the Zhambyl region of southern Kazakhstan have estimated natural

gas reserves of more than 777 Bcf, which would be enough to provide uninterrupted natural gas supplies to the southern regions of the country for at least 12 years. Kazakhstan started work at the Amangeldy deposit in the spring of 2001, and began drilling the first of four wells in August 2001. Complete development of the field will cost approximately $770 million, with production set to begin at the start of 2003. Kazakh officials hopes to become independent of Uzbek natural gas supplies by 2005.

Natural Gas Exports

Until recently, Kazakhstan has been limited in its ability to export its natural gas, since the country's natural gas fields were not linked to Russia's natural gas pipeline system. However, as investment continues to pour into the Kazakh natural gas sector, the country's natural gas production is set to increase dramatically, and provided that the necessary infrastructure is built, Kazakhstan soon could become a major natural gas exporter.

In August 2001, the Kazakh Ministry for Energy and Mineral Resources approved a 15-year strategy for developing the country's natural gas sector that would increase natural gas production fivefold. According to the strategy, which the Kazakh government approved, Kazakhstan is aiming to increase its natural gas production to 1.2 Tcf by 2005, to 1.66 Tcf by 2010, and to 1.84 Tcf by 2015. Key to this strategy is the development of natural gas reserves at Kashagan, Karachaganak, and Tengiz.

With domestic natural gas demand expected to remain stable, Kazakhstan will be able to increase its natural gas exports to nearly 1.2 Tcf by 1015, according to Uzakbai Karabalin, deputy minister of energy and mineral resources. In June 2002, Kazmunaigaz and Russia's Gazprom created KazRosGaz, a joint venture that will allow Kazakhstan to pipe its natural gas through the Russian pipeline system for the first time. According to Russian officials, KazRosGaz will have the ability to transport 125 Bcf of Kazakh natural gas via Russia, increasing up to 1.77 Tcf in the future.

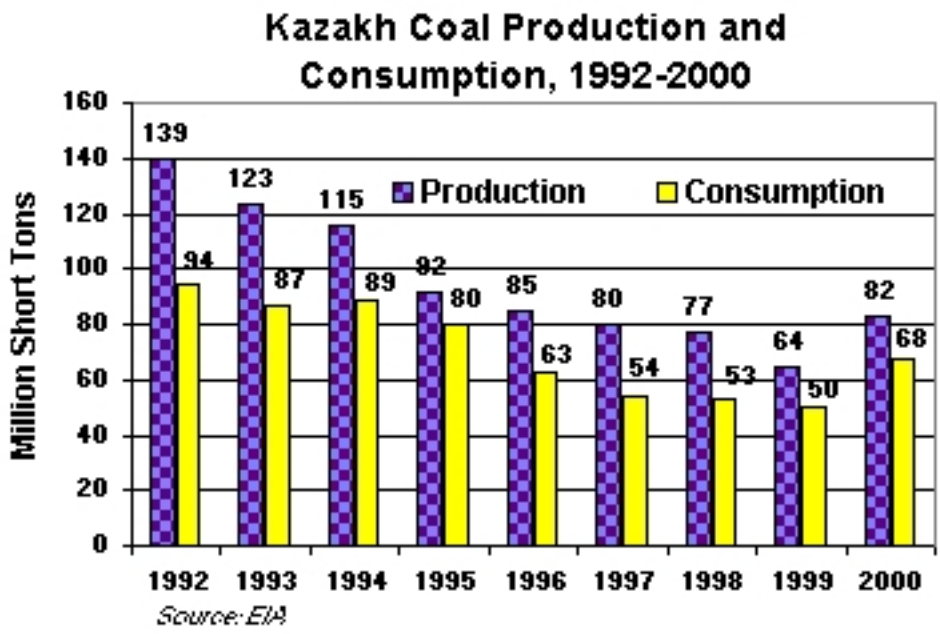
Since Kazakh natural gas is a potential competitor with Russian natural gas,

several new natural gas export pipelines from the Caspian Sea region also are in development or under consideration, potentially opening up new markets for Kazakh natural gas. In the meantime, Kazakhstan serves as an important natural gas transit center for Turkmen and Uzbek natural gas that is piped to Russia and beyond.

COAL

Despite a contraction of the industry since the breakup of the Soviet Union, Kazakhstan remains a major coal producer, consumer, and exporter. Kazakhstan was the third largest coal producer in the Soviet Union, trailing only Russia and Ukraine in total output. Between 1992 and 1999, however, Kazakh coal production, which is centered in the Karaganda and Ekibastuz basins, declined 54%, from 139.5 million short tons (Mmst) to 64.3 Mmst. Coal production declined in large part because of nonpayment by customers and the lack of incentives to export to Russia (due to high rail tariffs for transporting coal within Russia), as well as due to the collapse of domestic demand.

After nearly a decade of decline, Kazakh coal production increased to approximately 82.4 Mmst in 2000. According to Kazakhstan's official state statistics agency, Bogatyr Access Komir (BAK), the country's main coal mining enterprise that is a subsidiary of Access Industries, Inc. (U.S.), maintained its coal production level from 2000 in 2001, with production of about 35 Mmst of coal at the Bogatyr and Severny coal fields in northern Kazakhstan. Maikuben-Vest, which mines coal in the Pavlodar region, produced 1.99 Mmst of brown coal in the first ten months of 2001, 57.6% more than in the same period of 2000. Through the first six months of 2001, the Vostochny strip mine increased production 25.2% year-on-year, to 9 Mmst.



Coal accounted for about half of all primary energy consumption in Kazakhstan during the 1990's. From 1992 to 1999, Kazakhstan's coal consumption fell nearly 47%--from 94.2 Mmst to 50.3 Mmst. In 2000, the country's coal consumption increased for the first time since Kazakhstan's independence, with robust economic growth contributing to a 34% increase in coal consumption, to 67.6 Mmst.

Coal Exports

Kazakhstan's net coal exports to other former Soviet republics declined by two-thirds from 1991 to 1995 before making a modest recovery from 1996 to 2000. This decline in markets forced a severe cut in both coal production from Karaganda, which has a number of underground mines that produce high-quality coking coal. The high cost of extraction, combined with the drop in demand, forced a number of mines to close between 1991 and 1997. However, mines in Ekibastuz, the largest-producing area in Kazakhstan and the third largest coal basin in the former Soviet Union, have remained open and competitive after being privatized.

Kazakhstan is still the largest exporter of coal to the other former Soviet republics, accounting for almost half of the coal shipments among the republics. Russia remains the largest importer of Kazakh coal, followed by Ukraine. The Russian utilities Sverdlovskenergo and Chelyabenergo are major consumers of sub-bituminous coal from the Ekibastuz basin, and Sverdlovskenergo likely will continue to import coal from Kazakhstan since it acquired two Kazakh mines in 1996 as payment for unpaid debts for power supplied to Kazakhstan. In March 2001, Russia announced plans to import

between 30 Mmst to 40 Mmst of coal from Kazakhstan per year, possibly more, depending on the scale of Russia's economic growth.

With the recent move to cash payments for coal, some potential consumers of Kazakh coal have turned out to be insolvent. Nevertheless, in August 2001, Kazakh officials announced plans to increase the country's annual coal production to over 95 Mmst by 2005, of which about 60 Mmst will be used domestically and over 30 Mmst will be exported. BAK plans to produce 40 Mmst of coal in 2002 and 50 Mmst by 2005.

ELECTRICITY

Kazakhstan has 71 power plants, including five hydroelectric power stations, giving the country an overall installed generating capacity of 17.3 gigawatts (GW). Most of Kazakhstan's power plants are combined heat and power plants, approximately 70% of which use coal, 15% natural gas, and the remaining 15% hydroelectric power. Much of the country's electricity is generated by coal-fired plants that burn a dirty, high-ash coal, and the majority of the country's electric-generating equipment is old, inefficient, and lacking in modern pollution controls.

Sectoral Reform

Following the collapse of the Soviet Union in 1991, state-run Kazakhstanenergo inherited responsibility for operating the country's power-generating facilities and its 15 separate regional electricity distribution networks. As part of Kazakhstan's move to a market-based economy, in July 1997 Kazakhstanenergo was divested of its power generation facilities, creating independent generating companies, and then renamed the Kazakhstan Electricity Grid Operating Company (KEGOC).

Since then, in an effort to increase the efficiency of the power sector, Kazakhstan has privatized all of its power plants, but the sale of regional electricity distribution companies has proceeded more slowly, and the majority of the distribution networks have not yet been privatized. KEGOC has granted management rights to several private companies, but KEGOC

maintains control over high-voltage transmission lines, substations, and the central dispatching apparatus.

Non-payment of electricity bills, an inadequate collection system, and the lack of market-based transportation tariffs have been obstacles to further large-scale investment in Kazakhstan's transmission and distribution sector. Under the former Soviet system, Kazakhstan utilized a system of fixed electricity tariffs that were unrelated to production costs and investment needs. Kazakhstan's State Anti-Monopoly Committee is working to bring electricity tariffs in line with those in other countries and to allow the market to determine transmission tariffs. Effective July 1, 2001, KEGOC increased electricity transmission rates across the country by an average of 23.7%.

Power Generation and Consumption

After seven consecutive years of declining electricity production, in 2000 Kazakhstan generated 48.7 billion kilowatt-hours (Bkwh) of power, an 8% increase over 1999. Likewise, Kazakhstan's overall electricity consumption plummeted from 86.2 Bkwh in 1992 to 44.8 Bkwh in 1999, primarily due to a drop in demand from the industrial sector as output fell after independence. Owing to robust economic growth, Kazakh electricity consumption in 2000 rose 7.8% to 48.3 Bkwh. Kazakhstan's industrialized north produces about 80% and consumes about 70% of the country's electricity.

Although Kazakhstan technically generates enough electricity to meet its demand, the country has suffered from frequent power shortages since 1992 due to the sector's deteriorating infrastructure. Kazakhstan incurs large energy losses during transmission and distribution over its 285,000 miles of distribution lines. According to Kazakh Minister of Energy and Natural Resources Vladimir Shkolnik, an average of 15% of the electricity generated in Kazakhstan is lost before it reaches consumers, owing to the widespread deterioration of Kazakhstan's power infrastructure.

Transmission and Distribution

The power grids in northern Kazakhstan began to work parallel to Russia's

Unified Energy Systems in 1999 and later with the Unified Energy System of Central Asia (which also includes Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan) to solve the problem of uneven energy distribution in Kazakhstan. In January 2002, Kazakhstan withdrew from the Unified Energy System of Central Asia, citing a lack of formal agreement governing the system, but the country rejoined in April 2002 after signing five bilateral agreements with the other countries.

KEGOC estimates that it needs $258 million to reconstruct its electricity networks and overhaul its switching equipment in order to improve the reliability of its electricity supply, and to develop the power market through a power pool and improved access to the transmission network. In 1999, the World Bank's International Bank for Reconstruction and Development agreed to extend a $140 million loan to the government of Kazakhstan and KEGOC toward this electricity transmission rehabilitation project. Additional financing will be provided by KEGOC ($62.4 million) and the European Bank for Reconstruction and Development ($56 million). The U.S. Agency for International Development also is assisting Kazakhstan to develop a power pool for the regional distribution companies.

Since Kazakhstan's southern regions are largely dependent on expensive imported electricity supplies, KEGOC is considering building a second North-South power line to complement the existing, 600-MW-capacity line, making it possible to supply the country's southern regions fully with energy generated in Kazakhstan. The line would cost an estimated $300 million to build. In addition, Kazakhstan has made plans to construct five new combined heat and power stations: the 150-MW Uralskaya TETS, the 450-MW Aktyubinskaya TETS, the 300-MW Mainakskaya GES, the 1,280-MW Yuzhno-Kazakhstanskaya TETS, and the 500-MW Zapadno-Kazakhstanskaya TETS-1.

Nuclear Power

Kazakhstan's sole nuclear power plant--the 90-MW Mangyshlak Nuclear Power Plant at Aqtau--was shut down in April 1999 after nearly 26 years in

operation. In September 2000, the Kazakh government shelved plans to build a 640-MW nuclear plant in the east near Lake Balkash, citing cost and safety concerns, as well as public opinion opposed to the nuclear plant. Currently there are no plans to build any new nuclear plants in Kazakhstan.

COUNTRY OVERVIEW

President: Nursultan Nazarbayev (chairman of the Supreme Soviet from February 22, 1990; elected president December 1, 1991; re-elected to a seven-year term on January 10, 1999)
Prime Minister: Imangali Tasmagambetov (since January 2002)
Independence: December 16, 1991; National holiday: Republic Day, October 25, 1990 (date on which Kazakhstan declared its sovereignty)
Population (7/01E): 16.7 million
Location: Central Asia, bordering the Caspian Sea, Russia, Turkmenistan, Uzbekistan, Kyrgyzstan, and China
Size: 1,052,100 sq. miles (slightly less than four times the size of Texas)
Major Cities: Almaty; Astana (capital, moved from Almaty in December 1998); Karaganda; Shymkent
Languages: Kazakh (Qazaq, state language) 40%, Russian (official, used in everyday business) 66%
Ethnic Groups (1999E): Kazakh (Qazaq) 53.4%, Russian 30%, Ukrainian 3.7%, Uzbek 2.5%, German 2.4%, Uighur 1.4%, other 6.6%
Religions: Muslim 47%, Russian Orthodox 44%, Protestant 2%, other 7%

ECONOMIC OVERVIEW

Minister of Finance: Aleksandr Pavlov
Minister of Economy & Trade: Mazhit Yesenbayev
Currency: Tenge
Market Exchange Rate (7/12/2002): US $1=153.1 Tenge (KZT)
Nominal Gross Domestic Product (GDP) (2001E): $21.4 billion; **(2002E):** $22.9 billion
Real GDP Growth Rate (2001E): 13.2%; **(2002E):** 7.0%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 6.6%; **(2002E):** 5.6%

Official Unemployment Rate (2001E): 3.3%
Current Account Balance (2001E): -$1.35 billion; **(2002E): -**$1.75 billion
Major Trading Partners (1999): Russia, U.S., Uzbekistan, China, Turkey, U.K., Germany, Ukraine, South Korea
Merchandise Exports (2001E): $9.7 billion; **(2002E):** $9.8 billion
Merchandise Imports (2001E): $8.7 billion; **(2002E):** $9.3 billion
Merchandise Trade Balance (2001E): $1.0 billion; **(2002E):** $0.5 billion
Major Exports: oil, ferrous and nonferrous metals, machinery, chemicals, grain, wool, meat, coal
Major Imports: machinery and parts, industrial materials, oil and gas, vehicles
External Debt (12/01E): $13.8 billion

ENERGY OVERVIEW

Minister of Energy & Natural Resources: Vladimir Shkolnik
Chairman, Kazmunaigaz (National Oil & Natural Gas Company): Lyazzat Kiinov
Proven Oil Reserves (1/1/02E): 5.4 billion barrels
Oil Production (2001E): 811,000 bbl/d, of which 704,200 bbl/d was crude; **(2002E):** 887,900 bbl/d
Oil Consumption (2001E): 180,000 bbl/d
Net Oil Exports (2001E): 631,000 bbl/d
Crude Oil Refining Capacity (1/1/02E): 427,000 bbl/d
Natural Gas Reserves (1/1/02E): 65 trillion cubic feet
Natural Gas Production (2000E): 314.3 billion cubic feet (Bcf); **(2001E):** 324 Bcf
Natural Gas Consumption (2000E): 490.9 Bcf
Net Natural Gas Imports (2000E): 176.6 Bcf
Coal Reserves (1/1/02E): 37.5 billion short tons, of which 34.2 billion is anthracite and bituminous
Coal Production (2000E): 82.4 million short tons (Mmst)
Coal Consumption (2000E): 67.6 Mmst
Electric Generation Capacity (2000E): 17.3 gigawatts (GW)

Electricity Generation (2000E): 48.7 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 48.3 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Natural Resources & Environmental Protection: Andar Shukputov
Total Energy Consumption (2000E): 1.79 quadrillion Btu* (0.45% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 35.0 million metric tons of carbon (0.5% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 120.2 million Btu (vs. U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 2.4 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 95,916 Btu/ $1995 (vs. U.S. value of 10,918 Btu/ $1995)**
Carbon Intensity (2000E): 1.88 metric tons of carbon/thousand $1995 (vs. U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (1998E): Industrial (52.6%), Transportation (41.8%), Residential (5.5%), Commercial (0.0%)
Sectoral Share of Carbon Emissions (1998E): Industrial (56.3%), Transportation (38.1%), Residential (5.6%), Commercial (0.0%)
Fuel Share of Energy Consumption (2000E): Coal (46.9%), Natural Gas (28.5%), Oil (18.4%)
Fuel Share of Carbon Emissions (2000E): Coal (60.3%), Natural Gas (21.2%), Oil (18.5%)
Renewable Energy Consumption (1998E): 66 trillion Btu* (6% decrease from 1997)
Number of People per Motor Vehicle (1998): 12.2 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 17th, 1995). Signatory to the Kyoto Protocol (March 12th, 1999).

Major Environmental Issues: Radioactive or toxic chemical sites associated with its former defense industries and test ranges are found throughout the country and pose health risks for humans and animals; industrial pollution is severe in some cities; because the two main rivers which flowed into the Aral Sea have been diverted for irrigation, it is drying up and leaving behind a harmful layer of chemical pesticides and natural salts; these substances are then picked up by the wind and blown into noxious dust storms; pollution in the Caspian Sea; soil pollution from overuse of agricultural chemicals and salination from poor infrastructure and wasteful irrigation practices

Major International Environmental Agreements: A party to Conventions on Air Pollution, Biodiversity, Climate Change, Desertification, Endangered Species, Ozone Layer Protection, Ship Pollution. *Signed, but not ratified:* Climate Change.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY

Organization: Kazmunaigaz (vertically-integrated state oil and natural gas company, created in February 2002 by combining state-run Kazakhoil (oil) and TransNefteGaz (oil and natural gas transport, made up of KazTransOil and KazTransGaz)); Kazakhstanugol Corporation (state coal company); Kazakhstan Electricity Grid Operating Company (KEGOC)
Major Oil and Gas Fields: Tengiz (mostly oil), Karachaganak (mostly natural gas), Kashagan (oil), Uzen, Kumkol, Korolev, Tenge, Uritau (natural gas), Zhanazhol

Major Oil Ports: Atyrau and Aqtau on the Caspian Sea
Oil Export Pipelines: Tengiz-Novorossiisk (Russia); Uzen-Atyrau-Samara (Russia); Kenkyak-Orsk (Russia) line that transports oil from the Aktyubinsk fields to the Orsk refinery
Major Oil Refineries (crude oil refining capacity): Pavlodar (162,500 bbl/d); Atyrau (104,500 bbl/d); Shymkent (160,000 bbl/d)
Major Power Plants (capacity): Ekibastuz No.1 (4,000 megawatts, MW), Yermak (2,400 MW), Zhambyl (1,230 MW)

Sources for this report include: AFX-Asia, Agence France Presse, Associated Press, BBC Monitoring Central Asia Unit, Caspian News Agency, Caspian Business Report, Central Asia & Caucasus Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, Economist Intelligence Unit ViewsWire, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Interfax News Agency, ITAR-TASS News Agency, The Moscow Times, Oil and Gas Journal, Petroleum Economist, Platt's Oilgram News, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, The Times of Central Asia, U.S. Department of Commerce's Business Information Service for the Newly Independent States (BISNIS), U.S. Department of State, U.S. Deparment of Energy, U.S. Energy Information Administration, U.S. Department of State, World Markets Online.

LINKS

For more information from EIA on the Kazakhstan, please see:
EIA: Country Information on Kazakhstan
EIA: Caspian Sea Region

Links to other U.S. government sites:
U.S. Agency for International Development

CIA World Factbook
U.S. Department of Commerce's Business Information Service for the Newly Independent States (BISNIS): Kazakhstan
U.S. Department of Commerce's Country Commercial Guide: Kazakhstan
U.S. Department of Commerce, International Trade Administration: Energy Division
U.S. Department of Commerce, Trade Compliance Center: Market Access Information
U.S. Department of Energy, Office of Fossil Energy: International Affairs
Library of Congress Country Study on the former Soviet Union
Radio Free Europe/Radio Liberty
RFE/RL: Energy Politics in the Caspian and Russia
U.S. State Department: Background Notes
U.S. Department of State, International Information Programs
U.S. Embassy, Almaty, Kazakhstan

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Central Asia-Caucasus Institute of The Johns Hopkins University
Central Eurasia Project: Kazakhstan
Chevron: Kazakhstan and the Caspian Sea Region

ENI
EurasiaNet.org--News and Analysis from Central Asia and the Caucasus
European Bank for Reconstruction and Development
Harvard University: Caspian Studies Program
Interfax News Agency
Kazakhstan Information
Kazakhstan, Official Site of the President
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Central Asia: Turkmenistan Energy Sector

TURKMENISTAN

Following several years of decline after Turkmenistan's independence from the Soviet Union in 1991, Turkmenistan's economy has rebounded in the past four years. Turkmenistan, whose economy relies heavily on oil and natural gas production, suffered a 25.9% drop in its real gross domestic product (GDP) in 1997 when Russia closed off its natural gas pipeline network--Turkmenistan's sole natural gas export option at the time. Since the resolution of the dispute with Russia, Turkmenistan's natural gas exports have increased dramatically, spurring the country's economy to three straight years of double-digit real GDP growth, including an 18% increase in 2001. Turkmenistan's economy is forecast to grow an additional 13% in 2002.

Nevertheless, Turkmenistan's real GDP in 2001 was still only 70% of its 1990 level, and economic and political reform have been stifled under the autocratic leadership of President Saparmurat Niyazov, a former communist who has ruled Turkmenistan since independence and was named president for life in 1999. The country's unemployment rate, although down to 14% in 2001 from a high of 24.2% in 1998, is still problematic, and foreign direct investment, over 90% of which flows into the country's oil and natural gas sectors, has slowed over the past few years because of the restrictive conditions that Turkmenistan attaches to foreign investment. Privatization goals remain limited, and the country has not taken steps to diversify its economy to reduce its dependence on natural resource exports.

Oil

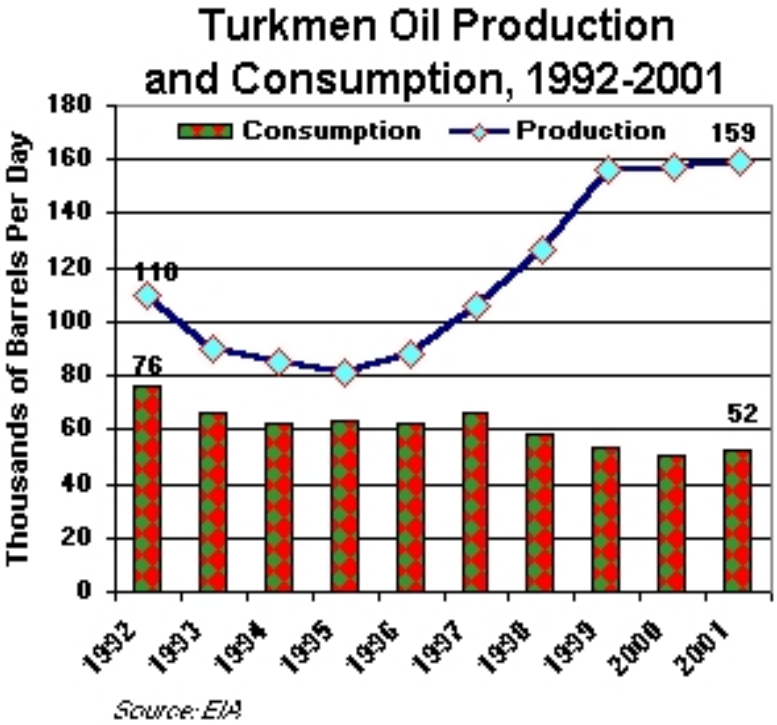
Turkmenistan has 546 million barrels in proven oil reserves, with possible reserves (mainly in the western part of the country and in undeveloped offshore areas in the Caspian Sea) of up to 1.7 billion

barrels. The country's oil production, which steadily declined after independence, from 110,000 barrels per day (bbl/d) in 1992 to 81,000 bbl/d in 1995, has increased dramatically in the past six years, reaching 156,400 bbl/d in 1999 before leveling off in the past two years. In 2001, Turkmenistan produced 159,000 bbl/d of oil while consuming 52,000 bbl/d. Turkmenneft, the state oil company, produced approximately 90% of this total, with the remainder coming from the state natural gas company, Turkmengaz, and several foreign oil companies operating under PSAs in Turkmenistan.

In 2002, Turkmenistan is seeking to increase its oil output to 200,000 bbl/d, with additional production to come from newly developed wells in the western part of the country. Under a 10-year program dictated by President Niyazov, Turkmenistan aims to raise its oil production to nearly 1 million bbl/d by 2010. According to Turmenistan's Oil and Gas Industry and Natural Resource Minister, Kurbannazar Nazarov, Turkmenistan needs $25 billion in foreign investment to its oil and natural gas sectors between now and 2010. In an effort to create a better business climate to attract foreign investment, in June 1998 Turkmenistan restructured its oil and gas industries into several state-owned companies.

Although the country has attempted to ease restrictions on foreign investment, many layers of regulation remain in place. Turkmenistan maintains prohibitive rules that prevent companies using subsurface resources to export hydrocarbons. Since foreign investors do not have access to export pipelines (state-run Turkmenneft, Turkmengaz, and Turkmenneftegaz, the oil and natural gas marketing company, currently own all of the country's pipelines), they are forced to sell the oil and natural gas they produce in Turkmenistan through the state commodities exchange or send it to refineries. Oil and natural gas are sold in Turkmenistan at fixed prices that are well below world market levels.

As a result, several projects that could substantially increase Turkmenistan's oil production have stalled. Petronas (Malaysia), which is developing the Cheleken-1 oil and natural gas deposit under a PSA signed in 1996, suspended operations for more than a year, since the company determined it could not develop the field profitably under Turkmenistan's export restrictions. Swap arrangements, such as United Arab Emirate-based Dragon Oil's small-scale swap agreement with Iran, have proved modestly successful, but the Turkmen government has pledged to work on legislation that will expand the opportunities for foreign investors to export oil and natural gas, including liberalizing pipeline transport and easing the tax burden.



Downstream/Refining

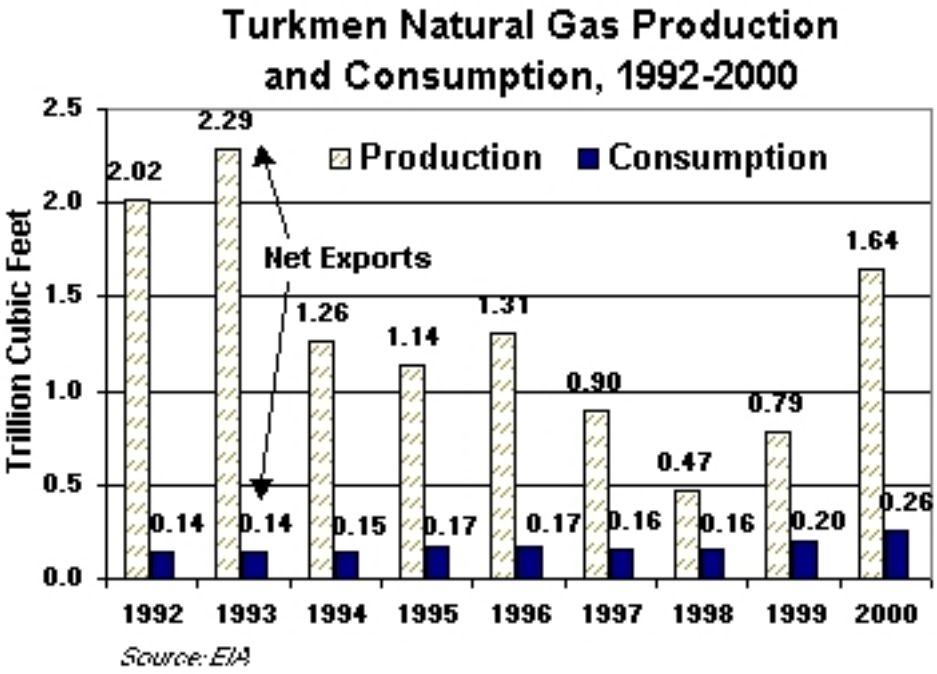
Turkmenistan has two refineries, the 116,500-bbl/d refinery at Turkmenbashy and a 120,500-bbl/d refinery at Seidi. Both facilities are slated for modernization and expansion to meet the country's expected increases in oil production and demand, and Turkmen President Saparmurat Niyazov is planning to call a tender in 2002 to build a new 100,000-bbl/d refinery. Work is underway on a $1.4-billion upgrade and modernization of the Turkmenbashy refinery, with financing from German and Japanese sources.

As part of the modernization, which is scheduled for completion in 2004, France's Technip was awarded a contract to build a lubricants blending plant. In April 2001, the catalytic cracking unit was launched by Technip and Iranian NINISC at a cost of $300 million. The unit, with a capacity of 36,150 bbl/d, is designed to produce high-octane gasoline, diesel, heating oil, and liquefied petroleum gas. Complete reconstruction of the refinery will give Turkmenistan the ability to produce motor oil, lubricants, and polymers to world standards, allowing the country to cease importing lubricating oils.

Natural Gas

Turkmenistan has some of the world's largest deposits of natural gas, with proven natural gas reserves of approximately 101 trillion cubic feet (Tcf). The largest natural gas fields are in the Amu-Dar'ya basin, with perhaps half of the country's natural gas reserves located in the giant Dauletabad-Donmez field. In addition to Amu-Dar'ya, Turkmenistan contains large natural gas reserves in the Murgab basin, particularly the giant Yashlar deposit, which contains an estimated 27 Tcf. During the last 10 years, Turkmenistan also has discovered 17 new natural gas deposits in the Lebansky, Maryinsky, and Deashoguzsky regions of the country.

Turkmenistan was a substantial natural gas producer under the Soviet Union, but after the country became independent, Turkmen natural gas became a competitor with Russian natural gas. Since Turkmenistan's only natural gas export routes ran through Russia, Gazprom limited Turkmen natural gas exports, and as a result Turkmenistan's natural gas production sagged throughout the 1990's. Following the resolution of a pricing dispute with Russia in 1998 and the construction of an export pipeline to Iran, Turkmenistan's natural gas production began to climb steadily. In 2001, the country's natural gas production jumped to 1.64 Tcf against consumption of just 0.26 Tcf. Turkmengaz produced 85% of this total, with Turkmenneft accounting for the remaining 15%.



With its large natural gas reserves, Turkmenistan is counting on increased natural gas production and exports to fuel its economic recovery. In May 2001, Turkmengaz started exploration and prospecting work on a new field in Darganata, northeastern Turkmenistan. Commercial exploitation of the Gagarinskoye deposit in Zaunguz Karakum is scheduled to begin soon, while resumption of work in the Samantepe field on the right bank of Amu Dar'ya in eastern Turkmenistan is planned. Under a presidential program, Turkmengaz also is stepping up exploratory work in the Karakum and Kyzylkum deserts. Through the first two months of 2002, Turkmenistan already had produced 413 billion cubic feet (Bcf) of natural gas.

In order to reach its full natural gas production potential, however, Turkmenistan must solve the problem of getting its natural gas to consumers, as well as getting paid in hard currency. The country has been unable to capitalize on its natural gas resources because it lacks pipeline outlets to world markets. As a result, Turkmenistan is forced to sell its natural gas to ex-Soviet states that either cannot pay fully in cash or are tardy with payments for supplies already received; both Azerbaijan and Kazakhstan are indebted to Turkmenistan for natural gas supplies. In October 2000, Turkmenistan agreed to resume the export of natural gas supplies to Ukraine that had been suspended in May 1999 because of Ukraine's $281-million natural gas debt.

In a bid to secure a market for its natural gas, on May 14, 2001, Turkmenistan agreed with Ukraine on a major natural gas export deal. Under terms of the deal, Turkmenistan will provide Ukraine with 8.83 Tcf of natural gas between 2002 and 2006. Turkmenistan will sell Ukraine 1.41 Tcf of natural gas in 2002 and 1.77 Tcf in 2003, with remaining deliveries to be agreed later. Turkmen officials signed the deal on the condition that Ukraine makes timely payments for supplies. Ukrainian officials agreed to pay for the Turkmen natural gas 60% in cash, with the remainder paid for through participation in 20 construction and industrial projects in Turkmenistan worth a total of $412 million.

Coal

Turkmenistan has no coal reserves, nor any coal production. Although the country consumed a minimal amount of coal during the Soviet era, in the aftermath of the collapse of the Soviet Union, Turkmenistan rapidly phased out its coal use, and the country's consumption fell from 551,000 short tons in 1992 to zero in 1998.

Electricity

With 3.9 gigawatts (GW) of installed capacity, 99% of which is thermal, Turkmenistan has sufficient electricity-generating potential to power its own cities, unlike much of Central Asia. In 2000, Turkmenistan's power sector generated 9.3 billion kilowatt-hours (Bkwh) while Turkmen consumers used just 7.7 Bkwh, giving the country 1.6 Bkwh in surplus electricity. However, owing to the country's inefficient, Soviet-era power infrastructure that is in need of repair, power line losses wasted a significant portion of the electricity Turkmenistan generated in 2000, resulting in exports of only 0.9 Bkwh.

Most of the electricity that Turkmenistan exports is sent to southwestern Kazakhstan and northeastern Afghanistan, although Armenia, Turkmenistan, and Iran have discussed greater cooperation in the energy sphere. A power transmission line connecting Turkmenistan to northern Iran would allow Turkmen electricity exports to Iran and to Armenia, since Armenia and Iran's electricity grids are connected.

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Japan

April 2002

Japan

Japan is the world's fourth largest energy consumer and second largest energy importer (after the United States). Over the past decade, Japan has been experiencing a period of slow economic growth, and has taken important steps towards economic deregulation and restructuring. As a result of slow economic growth, Japanese demand for energy has been stagnant in recent years, with oil consumption declining slightly.

Note: Information contained in this report is the best available as of April 2002 and is subject to change.

RECENT DEVELOPMENTS

After staging a modest recovery in 1999 and 2000, Japan's economy again slid into recession in 2001, as the global economic slowdown reduced demand for the country's exports. Japan's gross domestic product (GDP) fell by 0.4% in 2001, and it is projected to fall by 1.1% in 2002, though on a quarterly basis growth in real GDP is projected to resume in the second quarter of 2002. Unemployment has risen to over five percent, which is historically a very high level for Japan.

Japan's prime minister, Junichiro Koizumi, who took office last year, has pressed for structural reforms in Japan's economy. In one major change, Koizumi has reversed the previous policy of increasing government spending to stimulate the country's economy, and has set a deficit ceiling of 30 trillion yen. Spending on public works projects, which had been funded as part of previous stimulus packages, has been scaled back significantly in the proposed 2002/2003 government budget.

Japan's projected modest economic recovery in late 2002 is likely to be driven by growth in Japanese exports. Capital spending by Japanese businesses, however, and domestic demand for consumer products and services, are likely to recover more slowly. Despite an aggressive expansionary monetary policy by the Bank of Japan, with the discount rate currently set at 0.1%, consumer prices are likely to continue to fall through 2002.

Japan's economic stagnation since the early 1990s has led to a period of consolidation in the country's energy sector. Energy demand has been stable, and Japan's energy industries, particularly the downsteam oil sector, have undergone a period of downsizing and consolidation. Japan remains important to the world energy sector, though, as one of the main exporters of energy-sector capital equipment, and engineering, construction, and project management services.

ENERGY

Japan lacks significant domestic sources of energy and must import substantial amounts of crude oil, natural gas, and other energy resources, including uranium for its nuclear power plants. In 1999, the country's dependence on imports for primary energy stood at more than 79%. Oil provided Japan with 52% of its total energy needs, coal 15%, nuclear power 15%, natural gas 13%, hydroelectric power 4%, and renewable sources 1.3%. About half of Japan's energy is used by industry and about one-fourth by transportation, with nearly all the rest used by the residential, agricultural, and service sectors. Japan's energy intensity (energy use per unit of GDP) is among the lowest in the developed world.

OIL

Japan contains almost no oil reserves of its own (59 million barrels of proven oil reserves), but is the world's second largest oil consumer (after the United States). In 2001, Japan consumed an estimated 5.44 million barrels per day (bbl/d) of oil, down from 5.53 million bbl/d in 2000. Most (75%-80%) of this oil came from OPEC, particularly Persian Gulf countries like the United Arab

Emirates, Saudi Arabia, Kuwait, Qatar, and Iran. Japan has worked -- with relatively little success -- to diversify its oil import sources away from the Middle East. Another oil supplier to Japan is China, which, while it is a net oil importer, supplies light oil from its Daqing field for use in Japanese power plants. Until 1996, when Japan's oil consumption peaked at nearly 5.9 million bbl/d, Japanese oil consumption (and imports) had been growing steadily for years. After 1997, Japan's oil consumption declined as its economic slump caused demand by industrial and other users to decline.

Japanese oil companies have been active overseas since 1967, when the government established a state-run company to promote overseas oil exploration, the Japan National Oil Company (JNOC). Over the years, JNOC amassed numerous bad loans through extensive investment programs and loan guarantees to Japanese exploration firms. A study of JNOC for the Japanese Ministry of International Trade and Industry (MITI), conducted by the American consulting firm Booz Allen and Hamilton, concluded that Japan's policy of subsidies for oil exploration left firms with little incentive to seek high rates of return on their investments. In November 2001, Prime Minister Koizumi called for the abolishment of JNOC, and the Japanese government has been planning its liquidation and considering what role it should have in financing overseas oil projects. Under current plans, JNOC is to be shut down within three years, but the Japanese government will likely still make loans to support overseas oil projects by Japanese firms. Sales of some JNOC production assets already have begun.

The loss of drilling rights by Japan's Arabian Oil Company (AOC) in the Saudi Arabian portion of the Neutral Zone dealt a major blow to Japan's policy of seeking overseas equity in oil projects. AOC's rights to the concession, which produced 280,000 bbl/d, expired at the end of February 2000. Efforts to negotiate an extension with Saudi authorities failed when Japan refused to commit to investment in development projects desired by the Saudis. Saudi Aramco has taken over operation of the former AOC fields. AOC's concession for the Kuwaiti portion of the Neutral Zone expires in January 2003, and AOC has been in talks with the Kuwaiti petroleum ministry to try to secure its extension. While no final agreement has yet been signed, Kuwait reportedly has agreed to keep AOC as operator of the fields under a "service contract," rather than under a production sharing agreement (PSA), similar to other foreign firms involved in Kuwait's oil industry. AOC would guarantee Kuwait a purchase volume of no less than 100,000 bbl/d. A final decision on a new contract is expected by mid-2002.

Japan has been trying to make up for the loss of the AOC concession in Saudi Arabia by increasing its investment in Iran. Iran announced in November 2000 that it would begin exclusive negotiations with Japan Petroleum Exploration Corporation (Japex) and Indonesia Petroleum (Inpex), both of which are majority-owned by JNOC, for development rights to the huge onshore Azadegan oilfield. Azadegan has been estimated to contain 6 billion barrels of recoverable reserves. The consortium submitted a preliminary development plan for Azadegan in mid-2001, but progress in negotiations has been slow and no final agreement has been reached. The Japanese consortium has concluded an agreement to work with Shell on the project once a final contract is signed with Iran. The Azadegan field is expected to reach peak production of around 400,000 bbl/d once fully developed.

Apart from its interests in the Persian Gulf, Japan also has been seeking equity stakes in the Caspian Sea region. In July 1998, Mitsui purchased a 15% share, along with Azerbaijan's State Oil Company, of concessions in the Caspian Sea's Kur Dashi oil field. Oil reserves in the contract area are estimated at 500 million-1 billion barrels. In February 1999, JNOC announced that it would help finance the oil development project, the first since it revealed its major financial difficulties in June 1998. The Kur Dashi oil field is important to Japan's strategic goal of reducing its dependence on Middle Eastern oil imports. In December 1998, four other Japanese companies (Japan Petroleum Exploration Corp., Teikoku Oil Co., Indonesia Petroleum Ltd., and Itochu Corp.) signed a deal to purchase a different field (Atashgyakh-Mugandeniz-Yanan Tava) in the Caspian. JNOC's most significant purchase in 2000 was a 7% stake in Kazakhstan's offshore

Kashagan field in the Caspian Sea, through its subsidiary Inpex.

Refining/Downstream

As of January 2002, Japan had 4.8 million bbl/d of oil refining capacity at 33 refineries, down from 5.0 million bbl/d a year before. In recent years, as Japan's petroleum product consumption has stagnated, the country's refining industry has suffered from overcapacity. Japan also began to allow imports of petroleum products in the mid-1990s, putting additional pressure on Japanese refiners to cut costs and become internationally competitive.

In response to these pressures, Japan's refining industry went through a round of consolidations in 1999 and 2000. Nippon Oil and Mitsubishi Oil completed a merger in early 1999, forming Nippon Mitsubishi Oil. Nippon Mitsubishi then acquired Koa Oil from Caltex in September 1999, and in February 2002 merged Koa Oil with another subsidiary, Tohuku Oil. In October 1999, Nippon Mitsubishi announced a strategic alliance with another independent Japanese refiner, Cosmo Oil. The move, while not a merger, allows the two companies to coordinate distribution of refined products and to reduce costs through reduced duplication of some functions.

A second alliance coalesced around Showa Shell, Royal Dutch Shell's Japanese subsidiary, in which it owns a 50% stake. In January 1999, Showa Shell and Japan Energy announced a strategic alliance in petroleum product distribution and crude oil procurement.

The third major player in Japan's refining sector is ExxonMobil, through its Japanese subsidiary, Tonen General Sekiyu, which resulted from the merger of two ExxonMobil subsidiaries in February 2000. Tonen is the third largest of the alliances in terms of market share.

The only Japanese refiner outside of the major alliances is the privately-held Idemitsu Kosan. This refiner has a limited product sharing arrangement with Nippon Mitsubishi, but its debts make it an unappealing merger partner.

While many regulatory restrictions on Japanese refiners have been removed over the last few years, the firms remains saddled with a requirement to maintain mandatory large petroleum stocks. This requirement permits Japan to maintain a strategic reserve without having to build a government-run storage facility like the U.S. Strategic Petroleum Reserve, but also imposes significant additional capital costs on refiners operating in Japan.

NATURAL GAS

Japan has about 1.4 trillion cubic feet (Tcf) in proven natural gas reserves, with possibly more under the seabed surrounding Japan. Because domestic natural gas production is minimal, rising demand is being met by greater imports. About 97% of Japan's natural gas is imported, all in the form of liquefied natural gas (LNG). Most of this LNG comes from Southeast Asia, with 36% from Indonesia and 19% from Malaysia. The United States also supplies a small quantity of LNG to Japan from a facility in Alaska, which accounts for slightly over 2% of Japan's natural gas consumption. Most of the LNG is used either for electric power generation or as feedstock for petrochemical plants.

Three Japanese companies, Tokyo Gas, Osaka Gas, and Toho Gas signed a binding contract in February 2002 for the import of natural gas from Malaysia's MLNG Tiga project, covering deliveries beginning in 2004. The contract is noteworthy in that it includes much more flexible terms for the purchaser than most traditional LNG contracts, which commit the purchaser to a specific volume over 15 to 20 years. The three firms also renewed their baseload contracts with Malaysia's first two LNG export terminals, on terms more flexible than the original contracts. Tokyo Gas and Toho Gas signed a binding contract in October 2001 for LNG purchases from Australia's North West Shelf LNG project, to begin in 2004. Weak demand for electricity has undermined some LNG import projects, however, and Osaka Gas announced in April 2002 that it

was cancelling a planned LNG import terminal. Supplies to Japan from ExxonMobil's Arun LNG terminal in Indonesia resumed in September 2001 after being disrupted for several months due to civil unrest in the area. The main Japanese customer of Arun LNG is Tohuku Electric.

Japanese firms have been considering the possibility of imports, either by pipeline or as LNG, from large natural gas deposits on the Russian island of Sakhalin. ExxonMobil and Shell are backing rival development options - ExxonMobil a pipeline to Japan's main island of Honshu, and Shell an LNG export terminal which would have Japanese firms as its primary customers. Neither project yet has a firm agreement with a buyer, and major logistical obstacles due to the island's harsh climate and remote location remain problematic. ExxonMobil's feasibility study for its pipeline is due to be completed within a few months.

Much of Japan's urban area is not served by a natural gas distribution system. With plans to increase the natural gas portion of its primary energy supply to 13% by 2010, however, Japan is considering expansion of its internal natural gas pipeline system. Many analysts cite the absence of an effective natural gas distribution system as a key reason for Japan's high retail energy prices.

City gas consumption has increased by more than 70% in the last decade due to a 25% increase in natural gas customers and also to a large rise in consumption by industry. Japan's major natural gas companies include Tokyo Gas, Osaka Gas and Chubu Gas. The Japanese government has indicated that it plans to deregulate the retail natural gas sector in over the next several years to promote increased competition and lower prices.

COAL

Japan has small coal reserves of 865 million short tons (Mmst), and the country ceased production in January 2002 with the closure of its last operating coal mine at Kushiro, on the northern island of Hokkaido. Japan's coal mines had been heavily subsidized in recent years, since they were not cost-competitive with other producers.

Japan is by far the world's largest importer of steam coal, mainly for power generation, paper plants, and cement production. Japan also is the world's largest importer of coking coal for its steel industry. Overall, Japan accounts for about 22% of total world coal imports. Sources of imported steam coal are Australia, South Africa, the United States, and China. Japanese coking coal imports come mainly from Australia, Canada, the United States and Russia. Prices paid by Japanese firms for coal are currently declining, as increased exports of coal from China put downward pressure on the market.

In March 1999, Japanese coal firm Idemitsu agreed to participate in a coal development project in China's Shandong Province. Idemitsu hopes to secure coal supplies and in exchange, China will gain technical consulting from the Japanese firm. Idemitsu will evaluate coal quality, analyze combustion and test compatibility with boilers used in Japan. Prior to fiscal 2000, Idemitsu will help China to select coal deposits for mining, evaluate its quality and then set a target quality for exports to Japan. Production will begin at 2.1 Mmst annually and will eventually be sold to Japanese electric power companies. Japan and Vietnam signed an agreement for cooperation on coal technology in November 2000.

ELECTRICITY

Japan generated 1,018 billion kilowatthours (Bkwh) of electricity on 226 gigawatts of capacity in 1999. Of Japan's total generation in 1999, about 59% came from thermal (oil, gas, and coal) plants, 30% from nuclear reactors, 8% from hydroelectric dams, and less than 3% from geothermal, solar, and wind. Due to the country's desire to enhance its energy security, Japan has developed a large nuclear power industry. Despite its relatively high cost, natural gas, mainly imported as LNG, also is likely to experience considerable growth as a fuel for electricity generation. Renewables, chiefly hydropower and geothermal energy, also are expected to grow,

and both coal and nuclear are projected to grow in absolute terms (although nuclear power's share of the market is expected to drop). An accelerating decline is projected for oil-fired generation, which is still more significant in Japan than in most other developed countries. In the short-term, Japan's economic slowdown had resulted in a sharp downturn in capital spending by utilities, which has delayed several new power plant projects.

Japan's electricity prices are by far the highest in the OECD, and Japan has begun a program of reforms designed to make its electric utility sector more efficient. Currently, Japan is served by 10 vertically integrated utilities which each have a specific geographic zone. The Japanese Diet passed a bill in May 1999 which amended the Electric Utilities Industry Law (EUIL) to allow a partial opening to competition. Beginning in March 2000, about 8,000 large industrial and commercial Japanese electric power consumers, comprising roughly one-third of the Japanese power market, have been able to chose their electricity suppliers. Regional utilities currently are obligated to allow power from other suppliers to transit their grids to these large consumers.

While a small percentage of Japan's electricity has been provided by independent power producers (IPPs) since 1995, the new deregulation is expected to generate much more investor interest in developing IPPs, though progress in this direction has been slower than expected due to weak demand.

Nuclear Power

Japan's nuclear output nearly doubled between 1985 and 1996, as Japan attempted to move away from dependence on oil following the 1973 Arab oil embargo. During the past few years, public opposition to Japan's nuclear power program has increased in reaction to a series of accidents at Japanese nuclear plants, especially the accident at the Tokaimura uranium processing plant in September 1999. Other problems for Japan's nuclear power program have included rising costs of nuclear reactors and fuel, the huge investments necessary for fuel enrichment and reprocessing plants, several reactor failures, and the question of nuclear waste disposal. The safety record of the country's nuclear power industry has improved significantly since the Tokaimura accident, however, according to a recent Japanese government study.

By raising its reliance on nuclear-generated electricity, Japan is hoping to reduce its carbon dioxide emissions. Japan's current 10-year energy plan, approved in March 2002, calls for the expansion of nuclear generation by about 30% by 2010. This is expected to entail the construction by between 9 and 12 new nuclear power plants. The Japanese government also plans to offer subsidies for nuclear power plant construction, to offset expected cost-cutting pressures on utilities due to deregulation which might lead to increased reliance on fossil fuels for electricity generation. Currently Japan ranks third worldwide in installed nuclear capacity, behind the United States and France. Japan currently has 51 units in operation with an installed capacity of 45 GW.

In August 1998, the Atomic Energy Commission approved the construction of a new light-water reactor, which will be built in Higashidori in Aomori prefecture in northern Japan. Also, in March 1999, the Japanese Nuclear Safety Commission approved plans for Hokuriku Electric Power Co. to build a new nuclear power plant in the central town of Shika, which will be on line by 2006.

To enhance its energy security, Japan's government advocates uranium and plutonium recovery through reprocessing of spent fuel. The Power Reactor and Nuclear Fuel Development Corporation (PNC) operates a reprocessing plant with an annual capacity of 90 tons, but a larger reprocessing plant, Rokkasho-Mura, with a capacity of 800 tons per year, planned for completion in 2005, is under construction. Reprocessing is expensive and costs can quickly rise with new safety requirements and the development of new technologies. Estimated in 1993 to cost about $8 billion, more recent estimates put the cost of the facility much higher. In the meantime, Japan is negotiating with the French firm COGEMA for the reprocessing of spent nuclear fuel in France. COGEMA may continue to reprocess some spent fuel even after the Rokkasho plant is

completed. Japan also is interested in recycling recovered plutonium. In 1999, Japan began -- in two prefectures -- a controversial mixed-oxide utilization plan, which involves burning a highly toxic mix of plutonium and uranium on a commercial scale.

ENVIRONMENT

In recent years Japan has begun to take a more active role in protecting the environment. As air pollution in dense urban areas has persisted, the Japanese government has taken a number of measures to mitigate it, such as encouraging the adoption of low-polluting mass transportation buses and garbage collection vehicles as alternatives to diesel.

The effects of the oil shocks in the 1970s forced Japan to streamline heavy industrial production and reorient its economy toward less energy intensive industries. As a result, while Japanese energy consumption is high, Japan is a world leader in terms of energy efficiency, and a newly revised energy savings law is aiming to reduce the per capita energy consumption in Japan even further.

Japan committed to reducing its total carbon emissions by 6% under the 1997 Kyoto Protocol, but as Japan is the world's fourth largest producer of greenhouse gases, the task ahead is difficult. Japan's economy is heavily dependent on imported oil, but the government is placing increased emphasis on the diversification of its energy sources. In addition to nuclear power Japan is looking to increase its share of solar, hydro, and other carbon-free, non-polluting renewable energy sources. In the 21st century Japan will need to continue in its role as a leading developer of environmental technologies in order to protect its environment.

COUNTRY OVERVIEW

Chief of State: Emperor Akihito (since 1/7/89)
Prime Minister: Junichiro Koizumi (since 4/24/01)
Population (2001E): 126.8 million
Location/Size: Eastern Asia - island chain between the North Pacific Ocean and the Sea of Japan/145,882 square miles (slightly smaller than California)
Major Cities: Tokyo (capital), Osaka (Kansai), Nagoya, Fukuoka/Kitakyushu, Sapporo
Languages: Japanese
Ethnic Groups: Japanese (99.4%)
Religion: Shinto and Buddhist (84%), other (16%)
Defense (8/98): Army (151,800), Navy (43,800), Air Force (45,600), U.S. Forces in Japan (39,100)

ECONOMIC OVERVIEW

Currency: Yen
Exchange Rate (4/11/01): US$1 =130.8 Yen
Gross Domestic Product (GDP, at market exchange rate) (2001E): $4.1 trillion **(2002F):** $3.8 trillion
Real GDP Growth Rate (2001E): -0.4% **(2002F):** -1.1%
Inflation Rate (consumer prices)(2001E): -0.6% **(2002F):** -0.4%
Current Account Balance (2001E): $70.6 billion
Major Trading Partners: United States, Germany, Asian NIEs, China, OPEC
Merchandise Exports (2001E): $364.6 billion
Merchandise Imports (2001E): $300.7 billion
Merchandise Trade Surplus (2001E): $63.9 billion
Major Export Products: Machinery and transport equipment; chemical and other manufactured goods
Major Import Products: Chemical and other manufactured goods; machinery and transport equipment; mineral fuels; foodstuffs; crude material

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 59 million barrels
Oil Production (January 2002E): 73,620 barrels per day (bbl/d), of which 6,000 bbl/d is crude oil
Oil Consumption (2002E): 5.4 million bbl/d
Net Oil Imports (2002E): 5.3 million bbl/d
Crude Oil Refining Capacity (1/1/02E): 4.8 million bbl/d
Major Crude Oil Import Sources (2002E): United Arab Emirates, Saudi Arabia, Kuwait, Iran, Qatar, Indonesia
Natural Gas Reserves (1/1/02E): 1.4 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 0.08 Tcf
Net Natural Gas Consumption (1999E): 2.64 Tcf
Natural Gas Imports (1999E): 2.58 Tcf
Coal Reserves (12/31/96E): 865 million short tons (Mmst)
Coal Production (1999E): 4.1 million short tons (Mmst)
Coal Consumption (1999E): 149.5 Mmst
Net Coal Imports (1999E): 145.4 Mmst
Electric Generation Capacity (1/1/99E): 226 gigawatts
Electricity Production (1999E): 1,018 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Minister of Agriculture, Forestry, & Fisheries: Tokuichiro Tamazawa
Director General Environment Agency: Kayoko Shimizu
Total Energy Consumption (1999E): 21.7 quadrillion Btu* (5.7% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 306.6 million metric tons of carbon (4.9% of world total carbon emissions)
Per Capita Energy Consumption (1999E): 171.6 million Btu (vs U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 2.4 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 6,523 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 0.09 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (50.5%), Transportation (19.3%), Residential (15.8%), Commercial (14.4%)
Sectoral Share of Carbon Emissions (1998E): Industrial (50.1%), Transportation (25.1%), Residential (13.2%), Commercial (11.6%)
Fuel Share of Energy Consumption (1999E): Oil (52.1%), Coal (15.3%), Natural Gas (12.7%)
Fuel Share of Carbon Emissions (1999E): Oil (60.4%), Coal (26.6%), Natural Gas (13.0%)
Renewable Energy Consumption (1998E): 1,342 trillion Btu* (1% increase from 1997)
Number of People per Motor Vehicle (1998): 1.8 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified May 28th, 1993). Under the negotiated Kyoto Protocol (signed on April 28th, 1998, but not yet ratified), Japan has agreed to reduce greenhouse gases 6% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Air pollution from power plant emissions results in acid rain; acidification of lakes and reservoirs degrading water quality and threatening aquatic life; Japan is one of the largest consumers of fish and tropical timber, contributing to the depletion of these resources in Asia and elsewhere.
Major International Environmental Agreements: A party to the Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999

ENERGY INDUSTRIES

Organizations: Electric Power Development Co. (EPDC) - a quasi-governmental wholesale power company established in 1952 to help secure stable supplies of electricity. EPDC is scheduled for privatization within the next 5 years. Power Reactor and Nuclear Fuel Development Corp. (PNC, or Donen) -- the government nuclear oversight organization; Japan National Oil Company -- government owned
Major Oil Companies: Arabian Oil (Tokyo), Cosmo Oil, Tonen General Sekiyu, Indonesia Petroleum Ltd., Itochu, Japan Energy, Japan National Oil Corp. (JNOC), Japan Petroleum Exploration., Mitsui Oil Exploration, Nippon Mitsubishi Oil, Showa Shell Sekiyu, Sodeco, Sumitomo, Teikoku Oil
Major Electric Power Companies: Chubu Electric, Chugoku Electric, Hokkaido Electric, Hokuriku Electric, Japan Atomic Power, Kansai Electric, Kyushu Electric, PNC, Shikoku Electric, Tohoku Electric, Tokyo Electric
Major Refineries (capacity, bbl/d): Negishi (365,750), Ichihara -- Chiba (228,000), Mizushima (190,000), Cosmo -- Chiba (228,000), Showa Yokkaichi (222,000), Tonen Kawasaki (292,950)
Pipelines: Crude oil 52 miles; petroleum products 200 miles; natural gas 1,116 miles

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Sources for this report include: Coal Week International; Dow Jones News wire service; Economist Intelligence Unit ViewsWire; Electric Utility Week International; Kyodo News Service; Nikkei Shimbun; Oil and Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; U.S. Energy Information Administration; WEFA Asia Economic Outlook; World Gas Intelligence.

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Energy Information Administration

June 2002

Azerbaijan: Production-Sharing Agreements

Table 1: Offshore Production Sharing Agreements

Name of PSA	Project Partners	Estimated Reserves	Projected Investment	Project Status
Azeri, Chirag, and Deepwater Gunashli (Azerbaijan International Operating Company, AIOC) Signed Sept. 20, 1994; ratified December 1994	BP (34.1%, operator), Unocal (10.2%), Lukoil (10%), SOCAR (10%), Statoil (8.6%), ExxonMobil (8%), TPAO (6.8%), Devon Energy (5.6%), Itochu (3.9%), Amerada Hess (2.7%)	4.3 billion barrels of oil	$13 billion	Exports began late 1997. Producing 120,000 bbl/d at Chirag field as of May 2002. First exploration well drilled at Azeri field.
Shah Deniz Signed June 4, 1996; ratified October 17, 1996	BP (25.5%, operator), Statoil (25.5%), SOCAR (10%), LukAgip (10%), TotalFinaElf (10%), OIEC of Iran (10.0%) TPAO (9.0%)	2.5 billion barrels of oil; 25-39 Tcf of natural gas	Up to $4.5 billion	Natural gas extraction scheduled for 2004.
Lankaran-Talysh Signed Jan. 13, 1997; effective June 1997	TotalFinaElf (35%, operator), Wintershall (30%), SOCAR (25%), OIEC of Iran (10%)	700 million barrels of oil	$2 billion; $36.6 million invested by 2000	First test well (2001) came up dry.

Yalama/D-222 Signed July 4, 1997; ratified November 1997	LukArco (60%, operator); SOCAR (40.0%)	750 million barrels at Yalama field	$4 billion	Conducted 2-D and 3-D seismic work.
Absheron Signed Aug. 1, 1997; ratified November 1997	SOCAR (50%); Chevron (30%, operator), TotalFinaElf (20%)	13 billion barrels of oil; up to 100 Tcf of natural gas	$3.5 billion; $10.6 million invested by 2000.	First well drilled in 2001 with poor results.
Oguz Signed Aug. 1, 1997; ratified November 1997	ExxonMobil (50%, operator), SOCAR (50%)	550 million barrels of oil; 1.8 Tcf of natural gas	$2 billion; $5.5 million invested by 2000.	Dry well drilled in April 2001. ExxonMobil announced plans to quit the project in April 2002.
Nakhchivan Signed Aug. 1, 1997; ratified November 1997	ExxonMobil (50%, operator), SOCAR (50%)	750 million barrels of oil	$2 billion; $22.5 million invested by 2000	ExxonMobil drilled one successful well, will drill a second well.
Kurdashi-Araz-Kirgan Daniz Signed July 7, 1998; ratified July 1998	SOCAR (50%), Agip (25%, operator), Mitsui (15%), TPAO (5%), Repsol (5%)	1.3 billion barrels of oil	$2.5 billion	First test wells drilled, with poor results.

Inam Signed July 21, 1998; ratified December 1998	SOCAR (50%), BP (25%, operator), Royal Dutch/Shell (25%)	2.2 billion barrels of oil	$2 billion; $7.5 million invested by 2000	BP suspended drilling of its first appraisal well in Aug. 2001 due to high pressure.
Araz, Alov, and Sharg Signed July 21, 1998; ratified December 1998	SOCAR (40%), BP (15%, operator), Statoil (15%), ExxonMobil (15%), TPAO (10%), Alberta Energy (5%)	4 billion barrels of oil	$10 billion	Confrontation with Iranian gunboat in July 2001; exploration suspended, pending resolution of Caspian Sea borders between Azerbaijan and Iran.
Atashgah Signed December 25, 1998; ratified June 1999	SOCAR (50%), JAOC consortium (50%). JAOC divided as Japex (22.5%, operator), Inpex (12.5%), Teikoku (7.5%), and Itochu (7.5%)	750 million barrels of oil in Atashgah, Mugandeniz, and Yanan Tava fields	$2.5 billion; $35 million invested in 1999.	Seismic work being undertaken.
Lerik, Jenab, Savalan, Dalga Signed April 27, 1999	SOCAR (50%), ExxonMobil (30%, operator), unassigned (20%)	1 billion barrels of oil	$3 billion	Exploration D-43, D-44, and D-73 blocks
Zafar-Mashal Signed April 27, 1999; ratified April 2000	SOCAR (50%), ExxonMobil (30%, operator), Conoco (20%)	1-2 billion barrels of oil	$3 billion	Exploration D-9 and D-38 blocks

Table 2: Onshore Production Sharing Agreements

Name of PSA	Project Partners	Estimated Reserves	Projected Investment	Project Status
Kalamaddin-Mishovdagh (formerly AzPetoil JV) Signed as JV in 1992; converted into PSA in 2000	Moncrief Oil (49.3%, operator); Pet Oil (35.7%); SOCAR (15%)	200 million barrels of oil	$1 billion	Production averaged 2,750 bbl/d of oil in 2000.
Anshad Petrol Signed as JV in 1993; converted into a PSA in 2000	SOCAR (51%), Attila Dogan (31.5%), Land and General Berhard (17.5%)	219 million barrels at Neftchala, Khilly, Babazanan	--	Drilled 4 wells 1998-1999. Production averaged 900 bbl/d in 1999.
AzGeroil Signed as JV in 1995; converted into a PSA in 2000	SOCAR (51%), Grunewald (49%)	140 million barrels at Ramany, Balkhany, and Sabunchi fields	--	Production averaged 1,000 bbl/d in 1999.
Southwest Gobustan Signed June 2, 1998; ratified November 1998	Commonwealth Oil & Gas (67.25%, operator), SOCAR (20%), Sooner International (12.75%)	300 million barrels of oil; up to 900 billion cubic feet of natural gas	$900 million; planned $51 million in 2001	Still conducting 2-D seismic research.
Zykh-Govsany Signed June 5, 2000	SOCAR (50%); Lukoil (50%)	150 million barrels of oil	$250 million	Rehabilitating fields; produced 1,830 bbl/d in 2000.

Kursangi-Garabagli Signed December 15, 1998; ratified April 1999	SOCAR (50%), CNPC (30%), Amerada Delta-Hess JV (20%)	750 million barrels of oil	$1 billion	Two CNPC subsidiaries bought out EBRD stake (acquired from Frontera) in 1/02; fields currently producing 5,500 bbl/d
Muradkhanli-Jafarli-Zardab Signed July 21, 1998; ratified November 1998	Ramco (50%, operator), SOCAR (50%)	750 million barrels of oil	$1 billion	1st test well at Muradkhanli shut down in April 2001.
Padar-Kharami Signed April 27, 1999	Moncrief (80%, operator), SOCAR (20%)	750 million barrels of oil	$2 billion	Seismic work being undertaken.
Shirvanoil Signed as JV in 1997; converted into a PSA in 2000	SOCAR (60%), Whitehall (40%)	650 million barrels of oil at Kyurovdag field	--	Rehabilitating existing wells since 1997. Production averaged 4,350 bbl/d in 2001.

West Absheron (Karadag-Kergez-Umbaki fields) Signed August 10, 1994	BMB (100%)	200 million barrels of oil	$700 million	SOCAR moved to take over the concession in December 1999 following BMB's request to suspend operations.

Figure 1: Map of Azerbaijan Production Sharing Agreements

Return to Azerbaijan Country Analysis Brief

July 2002

Caspian Sea Region: Legal Issues

Caspian Sea map. Having problems, call our National Energy Information Center on 202-586-8800 for help.

CASPIAN SEA ISSUES

Questions surrounding the legal status of the Caspian Sea have hindered--but not stopped--further development of the Sea's mineral resources. Since the fall of the Soviet Union in 1991 led to the independence of three new countries bordering the Caspian, the littoral states--Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan--have been unable to agree on a legal framework governing the use and development of the Sea's oil and natural gas reserves.

The main difference of opinions among the five littoral countries lies in the uneven distribution of potential oil and natural gas riches in the region. This fact was brought to the forefront when Iranian military gunboats confronted an Azeri research vessel in the Caspian in July 2001. Although the Azeris stated that they were exploring their sector of the Caspian, the Iranians ordered the ship to vacate the area, claiming the waters where the ship was exploring remain in dispute. This military confrontation raised the stakes in the ongoing disagreement between the littoral states and highlighted the need for a legal framework on the status of the Caspian that clarifies ownership of its bountiful natural resources. From a legal perspective, the key issues include:

- Whether, in the absence of a new legal convention, treaties signed between the former Soviet Union and Iran are still in force and thereby govern current development rights. The Soviet Union and Iran signed bilateral treaties on the Caspian Sea in 1921 and 1940, but neither established seabed boundaries or discussed oil and natural gas exploration;

- The need to develop a legal framework to resolve environmental and biological issues. Several countries have opposed the laying of proposed trans-Caspian oil and gas pipelines on environmental grounds;

- Whether the Caspian is a body of water covered by the Law of the Sea Convention, which does not cover inland lakes. If the Law of the Sea convention were applied to the Caspian Sea, full maritime boundaries of the five littoral states bordering the Caspian would be established based upon an equidistant division of the sea and undersea resources into national sectors. However, if

the Law of the Sea were not applied, the Caspian and its resources would be developed jointly--a division referred to as the "condominium" approach.

A working group made up of representatives from each country was created to draw up a joint declaration on the new legal status of the Caspian Sea, but the group failed to make progress on settling differences. After the working group's second meeting in December 1998, subsequent meetings were canceled in order to give participants more time to move towards common ground.

Working Toward Consensus

In the absence of a formal agreement among the five countries on the legal status of the Caspian, several countries have negotiated bilateral agreements to clarify their positions. Rather than arguing whether the Caspian is a lake or an enclosed sea and dividing the Sea accordingly, in 1997, Kazakhstan and Azerbaijan agreed "to adhere to the borders of the sectors along the median line" until a convention on the legal status of the Caspian is signed. Also in 1997, Kazakhstan signed a communiqué with Turkmenistan pledging to divide their sections of the Caspian along median lines, based upon Soviet-era divisions, until the littoral states agreed upon a new status for the Caspian.

In July 1998, Kazakhstan signed a bilateral agreement with Russia dividing the northern Caspian seabed only along median lines between the two countries, with the waters (covering issues such as shipping, fishing, and environment) remaining under joint ownership. Under this accord, Russian agreements with Iran on the division of the Caspian that date back to Soviet days would remain valid until an overall agreement is reached among all Caspian littoral states.

Former Kazakh Prime Minister Kasymzhomart Tokayev stated that Kazakhstan would consider modifying the median line on economic considerations; i.e., future hydrocarbon finds, although he insisted that within these economic zones the states would have an exclusive right to exploit natural resources. The breakthrough for Russia and Kazakhstan came after they agreed to the joint development of deposits located on the median line, including the Kurmangazy structure in Kazakhstan and the Khvalynskaya field, which is part of Lukoil's (Russia) Severny block. The understanding is that Kazakh companies can take part in Khvalynskaya, while Kurmangazy will be opened to Russian companies.

Caspian Sea Proposed Median Lines map. Having problems, call our National Energy Information Center on 202-586-8800 for help.

In January 2001, Azerbaijan President Heydar Aliyev and Russian President Vladimir Putin issued a joint communiqué agreeing to divide the Caspian Sea on the seabed, but keeping navigation on the entire water surface free. Under this "common water, divided sea floor" approach, the sealer could be "divided into sectors/zones among corresponding neighboring and oppositely-located states, on the principle of a median line drawn at equal distance from the sides and modified at their mutual consent."

Azerbaijan formerly had advocated for the division of the surface, water, and seabed. At the Commonwealth of Independent States (CIS) Summit in November 2001, Kazakhstan and Azerbaijan formally signed a bilateral agreement defining their sectors of the Caspian Sea. Azerbaijan and Russia are also finalizing a bilateral agreement on the Caspian Sea.

In another sign of progress towards developing a legal convention on the status of the Sea, the Caspian Working Group, comprised of the deputy foreign ministers of each of the five countries, is once again meeting regularly. At the group's session in Moscow in January 2002, the deputy foreign ministers signed a joint communiqué on the legal status of the Caspian Sea. According to Russian Presidential Special Envoy for the Caspian Sea Victor Kaluzhny, the communiqué "covers many interregional issues of five littoral states," in particular, the current political events of Azerbaijan, Iran, Kazakhstan, Turkmenistan, and Russia, as well as positions of the sides on the situation in Afghanistan.

However, the deputy foreign ministers still were not able to reach a final agreement on the Caspian. Although Kaluzhny suggested that the Caspian could receive a new legal status as early as the first half of 2002, several sticking points remain that could prevent a formal agreement. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status, prompting Russia and Kazakhstan to finalize their biilateral agreement.

Remaining Issues To Be Decided

Although the Caspian Sea littoral states have made progress in the working group in bringing their positions closer together, a final agreement remains out of reach. There is now general agreement between Russia, Azerbaijan, and Kazakhstan on both "the principle and the method" of dividing rights to the seabed and the mineral wealth beneath it, but Turkmenistan only agrees on the principle of dividing

the Sea, and Iran disagrees with both the principle and method of dividing the Sea and its resources.

Iran's continued insistence on equal division of the Caspian Sea resources is now potentially the biggest obstacle to a formal agreement on the Caspian's legal status. In addition, although dividing the seabed would provide each country with control over its own resources, the exact location of these median lines has not been decided. Environmental concerns about the Caspian also need to be addressed.

Iran's Unwavering Stance

At the present time, Iran assumes the most isolated position among the littoral states on the division of the Sea. Iran insists that regional treaties signed in 1921 and 1940 between Iran and the former Soviet Union, which call for joint sharing of the Caspian's resources between the two countries, are valid. Iran has rejected as invalid all unilateral and bilateral agreements on the utilization of the Sea. While Iran agrees that a new legal convention is necessary, Iranian Foreign Minister Kamal Kharrazi told a meeting of deputy foreign ministers of the Caspian states in Tehran in February 2001 that the 1921 and 1940 treaties should be the basis for adopting a new legal regime.

As such, Iran is insisting that either the sea should be used in common, or its floor and water basin should be divided into equal shares. Iran's preference is for the countries around the sea to use it by consensus. Under this plan, the so-called "condominium" approach, the development of the Caspian Sea would be undertaken jointly by all of the littoral states. Iran wants all Caspian states to approve any offshore oil developments until the legal status of the Caspian Sea is agreed upon by all of the littoral countries. Another Iranian suggestion is that the littoral states should suspend all work in the Caspian Sea until the new legal status of the Caspian is determined. However, several countries are proceeding with development of subsea resources in what are generally considered to be their national waters, making the condominium approach less likely.

Iran has indicated a willingness to divide the Caspian Sea into national sectors, but only provided there is equal division of the Sea, giving each country 20% of the sea floor and surface of the Caspian. However, using the equidistant method of dividing the seabed on which Kazakhstan, Azerbaijan, and Russia have agreed, Iran would only receive about 12% to 13% of the Sea. Both Kazakhstan and Azerbaijan openly have opposed Iran's proposal to divide the Caspian into five equal sectors, stating that that does not correspond to historical traditions. Nevertheless, Iran continues to insist on receiving 20% of the Sea, and diplomats involved in the working group negotiations have said that Iran has been willing to bide its time in talks in a bid to maximize its share of the Caspian Sea.

Competing Claims and Overlapping Fields

In addition to Iran's unwavering stance are the twin problems of competing claims and overlapping fields. Central to both of these problems is where the modified median line will be drawn to demarcate national sectors. Azerbaijan, Russia, and Kazakhstan have agreed in principle on a division which would give them shares extending out from their respective coastlines. Where national zones met in the middle of the sea, borders would be equidistant from the facing coastlines.

According to diplomats involved in the working group meetings, Turkmenistan agrees in principle to dividing the seabed, but not via this method. Furthermore, the potentially difficult question about the division of oil and natural gas fields that overlap offshore boundaries has not been decided yet.

Caspian Sea Proposed 45-mile Zone Divisions map. Having problems, call our National Energy Information Center on 202-586-8800 for help.

In February 1998, Azerbaijan and Turkmenistan issued a statement saying that they agreed that the Caspian Sea between Azerbaijan and Turkmenistan would be divided along a median line, but disagreements over where to draw that line caused a dispute over a field called Kyapaz by Azerbaijan and Serdar by Turkmenistan. Azerbaijan reached a preliminary agreement to develop this field in July 1998, and Turkmenistan laid claim to it by including it as part of its Block 30 licensing in September 1998.

Uncertainties over legal ownership of fields in the Caspian Sea were a contributing factor to the failure of Turkmenistan's first tender for production-sharing agreements on Turkmenistan's Caspian shelf, which included the Serdar field. Azerbaijan and Turkmenistan continue to disagree over where to draw the median lines, particularly over the Kyapaz/Serdar field. Turkmenistan repeatedly has called on Azerbaijan to halt to freeze the development of disputed deposits until the legal status of the Caspian is agreed and borders are drawn up, but in the meantime, Azerbaijan has stated that the 1970 division of the Caspian by the Soviet Ministry of Oil and Gas, which assigned the Kyapaz field to Azerbaijan, remains in force.

Turkmenistan considers that the method of dividing the Sea along a median line proposed by Azerbaijan does not take into consideration geographical peculiarities connected with the features of the shore, particularly Azerbaijan's Absheron peninsula, which juts out into the Sea. Turkmen officials say this method has led to significant deviation of the median line.

Rather, Turkmenistan wants the border line in the middle of the Sea--where its zone would meet that of Azerbaijan--to be drawn using a more approximate method, which would give it a slightly larger share of a mid-sea area where some of the best oil prospects lie. Turkmenistan wants to divide the floor along a meridian line based on the shores of the states lying opposite. Another option, according to the Turkmen side, would be for each of the Caspian states to establish a 12-mile zone along the coast. To this zone would be added a 35-mile "zone of economic interests" of each of the states, with the remaining part of the sea open for shipping by all of the Caspian states.

Disagreement between Azerbaijan and Turkmenistan over the division of the Sea has led to additional conflicts over field ownership. Turkmenistan claims that portions of the Azeri and Chirag fields--which Ashgabat calls Khazar and Osman, respectively--lie within its territorial waters. Turkmenistan has alleged that Azerbaijan is illegally working at the Khazar and Osman fields, and in July 2001, Turkmenistan demanded that Baku suspend all work at the disputed fields or "be answerable for the consequences."

In August 2001, Azerbaijan struck back, rejecting a warning that its oil exploration in a disputed part of the Caspian Sea was illegal by stating that it would not accept "any claims aimed at thwarting the realization of its sovereign rights in a sector of the Caspian Sea which belongs to Azerbaijan."

While the war of words between Azerbaijan and Turkmenistan over the Kyapaz/Serdar dispute has been highly publicized, it was superseded by another conflict over field ownership that arose between Iran and Azerbaijan in July 2001. On July 22, 2001, the Iranian Oil Ministry issued a warning to foreign energy firms about working with other states in areas of the Caspian Sea which Iran considers its territory.

The following day, tensions flared when an Iranian gunboat ordered a British Petroleum (BP) oil exploration ship, licensed to explore Azeri waters, out of what it regarded as the Iranian sector. The Geofizik-3, with BP specialists aboard, was exploring in the Araz-Alov-Sharg concession, an area 90 miles southeast of Baku, which was licensed to a BP-led consortium in 1998 by the Azeri government.

Iran disputed the legitimacy of the license, claiming that the block, which Iran calls Alborz, is in Iranian waters. BP has suspended work at the field, pending resolution of the dispute between the two countries. Although the incident was the first overt military act in the Caspian since the collapse of the Soviet Union, it was not the only disagreement between Iran and Azerbaijan. In 1999, Azerbaijan accused Iran of encroaching on what Baku considered its sector of the Caspian after Tehran reached a deal with Royal Dutch/Shell and Lasmo to carry out a seismic survey in parts of the sea.

Ecological Concerns

The Caspian Sea is home to the world's largest sturgeon population, which produces caviar. The economic importance of the region's caviar industry has united the littoral states in their concern over the environmental risks of oil and gas development in the Caspian Sea. Thus, after a number of regional environmental agreements were signed in the aftermath of the Soviet collapse, in May 1998 the Caspian Sea littoral states established the Caspian Environment Programme (CEP) in Baku. The CEP is responsible for coordinating the joint protection and management of the Caspian environment and its resources by the Caspian States.

Russia has suggested that the CEP should keep tight control over the implementation of all projects which might lead to a deterioration in the ecological situation in the Caspian. As such, Russia and Iran have stated their opposition to the laying of trans-Caspian pipelines until a legal framework is established to govern environmental and biological issues, and to establish legal responsibility for safe use of the Caspian Sea. Kazakhstan also has stated that cooperation on the environment, fishing, and navigation in

the Caspian Sea would be beneficial.

IRANIAN EMBARGO AND SANCTIONS

After U.S. oil company Conoco signed an agreement with Tehran in 1995 to develop Iran's Sirri field, then-U.S. President Bill Clinton issued three executive orders that together established a total embargo on U.S.-Iran trade. They were intended to respond to Iran's support of international terrorism, efforts to undermine the Middle East peace process, and acquisition of weapons of mass destruction and the means to deliver them, a three-fold objective that remains the rationale for U.S. sanctions today.

The first executive order prohibits U.S. companies--but not their foreign subsidiaries--from supervising, managing, or financing projects relating to the development of Iran's oil and gas resources. A second executive order, issued on May 6, 1995, established comprehensive economic sanctions on Iran, again applicable to U.S. companies but not their offshore subsidiaries. Under this order, U.S. citizens may not trade in Iranian oil, finance, broker, approve or facilitate such trading, or finance or supply goods or technology that would benefit the Iranian petroleum sector.

Finally, in August 1997, President Clinton issued a third executive order that closed loopholes in the embargo whereby goods were being exported to Iran from third countries. Following President Clinton's executive orders, Conoco was forced to pull out of the Sirri project, which went to France's TotalFinaElf.

Iran and Libya Sanctions Act

Notwithstanding comprehensive unilateral sanctions against Iran and Libya (which date to 1986), the Iran and Libya Sanctions Act (ILSA) was enacted by Congress in August 1996. ILSA had many of the same objectives as the unilateral sanctions, but is different in jurisdictional scope. Unlike the embargoes against Iran and Libya, which are primary sanctions, ILSA imposes a secondary boycott. The legislation was designed essentially to force foreign companies into choosing to do business with Iran and Libya or the United States.

ILSA mandates the U.S. president to impose sanctions on any U.S. or foreign person who, after August 5, 1997, invests $20 million or more in an Iranian project ($40 million for Libya; this was lowered to $20 million in August 2001), if the investment directly and significantly contributes to the enhancement of Iran's or Libya's ability to explore for, extract, refine, or transport by pipeline its oil and natural gas reserves. ILSA requires that sanctions be imposed for a minimum of two years.

These prohibitions in ILSA, as well as the executive orders, would likely apply to any joint-use arrangements in the Caspian Sea, including the Iranian sector of the Caspian Sea. The U.S. has opposed large-scale oil swaps with Iran by U.S. companies. However, ILSA does not prohibit foreign companies from trading in Iranian crude oil and gas commodities, and in 1997, the U.S. State Department decided that proposed exports of natural gas from Turkmenistan to Turkey via Iran did not technically violate U.S. law.

Although ILSA initially may have had some effect in deterring investment by companies that did not

wish to risk sanctions, the law has never been enforced. At the first test of the law, when France's TotalFinaElf, Russia's Gazprom, and Petronas (Malaysia) signed a $2-billion agreement to develop Iran's South Pars field, the Clinton Administration granted a waiver to the companies in order to avoid clashes with its European allies. The Clinton Administration chose not to pursue several other potential violations, and in recent years ENI (Italy), Royal Dutch/Shell, TotalFinaElf, and BP have agreed to large projects in Iran without reprisal from the U.S.

On August 3, 2001, President George W. Bush signed legislation extending ILSA for an additional five years. In a statement issued by the White House press office that day, President Bush said that he approved of provisions added to the ILSA legislation that call for frequent review of sanctions to assess their "effectiveness and continued suitability."

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July 2002

Caspian Sea Region: Natural Gas Export Options

In addition to problems related to the unresolved legal status of the Caspian Sea and several regional conflicts, natural gas exports from the Caspian region have been hindered by geography. The majority of the Caspian Sea region's natural gas reserves are located on the east side of the Caspian, in relatively remote Turkmenistan, Kazakhstan, as well as in Uzbekistan. This distance from markets, as well as the lack of infrastructure to deliver this natural gas to customers, has tempered interest in the Caspian region's natural gas potential.

However, the 1999 natural gas discovery of Azerbaijan's Shah Deniz field appears to have boosted the region's natural gas export prospects. The Shah Deniz field, thought to be the largest natural gas discovery worldwide since 1978, already is being developed for export to Turkey, and the infrastructure that will be built to deliver this natural gas has helped to renew international interest in the region's natural gas.

In addition, Kazakhstan is beginning to tap its huge natural gas production potential, with plans to become a net natural gas exporter in the near future, and Turkmenistan is seeking to boost its natural gas output. Although the infrastructure to deliver this natural gas to customers will be costly, multiple routes for Caspian region natural gas exports have been proposed.

Northwest, via Russia

Prior to 1997, the only option for exporting Caspian region natural gas was via the Russian natural gas pipeline system. Although over 2 trillion cubic feet (Tcf) of Caspian Sea region natural gas was piped via the Central Asia Center gas pipeline in 1990, exports fell to 0.3 Tcf in 1997 when Russia's Gazprom, which is a competitor with Turkmen natural gas and owns the Russian pipelines through which Turkmenistan exports, denied Turkmenistan access to the system over a payment dispute.

Following resolution of this dispute, Turkmenistan exported 1.1 Tcf of natural gas via Russia in 2000, with 918 billion cubic feet (Bcf) sent to Russia and 177 Bcf contracted to Ukraine. Turkmenistan and Gazprom have agreed to increase shipments of Turkmen natural gas via Russia to between 1.8 Tcf and 2.1 Tcf per year by 2005 to 2006, with total capacity on this line as much as 3.5 Tcf per year. On May 14,

2001, Turkmenistan and Ukraine agreed to a major natural gas export deal through 2006 under which Turkmenistan will provide Ukraine with a total of 8.83 Tcf of natural gas via Russia between 2002 and 2006.

The existing Russian natural gas pipeline system also could be expanded to allow Central Asian natural gas exports to enter the Russian pipeline system en route to European customers. Existing pipelines through Kazakhstan and Russia have the capacity to transport over 700 Bcf per year, and capacity could be increased by an additional 50% by adding more compressors. The Russian natural gas pipelines through Astrakhan and Dagestan provide other options for Caspian region exports. Another proposal has been to transport natural gas from Kazakhstan to a proposed new LNG terminal on the Taman peninsula in Russia, where it would be transported to world markets via tankers.

Caspian region natural gas exports could also reach the growing Turkish natural gas market via Russia. This could occur by using an existing Russian natural gas pipeline to Georgia and connecting to a proposed new pipeline from Georgia to Turkey, possibly passing through Armenia en route. However, construction of this pipeline has been shelved as Russia concentrates instead on its own Blue Stream pipeline to deliver gas to Turkey.

The Blue Stream pipeline, scheduled to be completed in the spring of 2002, will pass under the Black Sea from the Russian port of Tuapse to the Turkish coastal city of Samsun. Rather than building a competing pipeline to transit Caspian natural gas via its territory to Turkey, Russia is likely to buy Caspian region natural gas and then re-export that natural gas to Turkey via the Blue Stream pipeline.

West, via Georgia to Turkey (and on to Europe)

Demand for natural gas in Turkey, the region's largest energy consumer, is projected to increase over the next 10 years. As such, Caspian region natural gas exporters are competing to supply the Turkish market, and Georgia could become a major transit center for natural gas. In addition, in March 2002 Turkey and Greece signed a memorandum of understanding to build a $300 million natural gas pipeline linking the two countries, allowing Caspian Sea region natural gas to reach European Union consumers.

After months of negotiation and delay, Azerbaijan and Turkey signed a long-term natural gas purchase and supply contract on March 12, 2001. Starting in 2004, Azerbaijan will deliver 70 Bcf of natural gas to Turkey, rising to 233 Bcf in 2007 and continuing until 2018. Natural gas for the deal will come mainly from Azerbaijan's Shah Deniz field, which is scheduled to come online in 2004. In order to deliver this natural gas, it will be necessary to construct a pipeline from Baku to Erzurum in eastern Turkey, where the natural gas will join the Turkish natural gas distribution system. Originally, Azeri officials had hoped to use the existing Soviet-era Gazi-Magomed-Gazakh pipeline, but technical inspection of the pipeline, along with the planned export volumes, determined that a new pipeline will be necessary.

The Baku-Erzurum pipeline will stretch some 630 miles, including 290 miles in Azerbaijan and approximately 170 miles in both Georgia and Turkey. Currently, the pipeline project is estimated to cost $1 billion. Credits to be drawn from international financial institutions, including the World Bank,

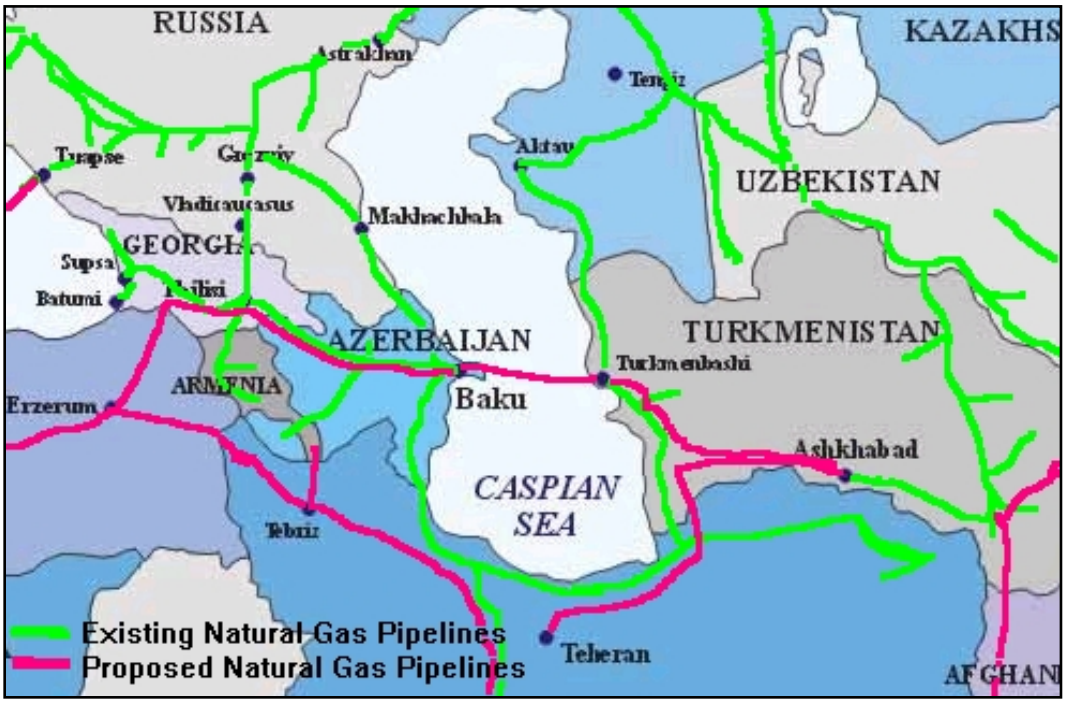
European Bank for Reconstruction and Development (EBRD), International Finance Corporation (IFC), and investors from the United States and Japan are expected to cover 70% of the pipeline's construction costs, while shareholders in the development of the Shah Deniz field development will contribute the remaining 30%.

In September 2001, Georgia and Azerbaijan cleared a major hurdle for implementation of the pipeline plan by signing a transit agreement. The Azeri parliament ratified the transit agreement in October 2001, followed by the Georgian parliament in December 2001. In January 2002, Georgia announced it would build two, 88.3-Bcf-capacity underground natural gas storage facilities in the east and southwest of the country as part of the pipeline project.

Construction of the Baku-Erzurum pipeline is scheduled to begin in late 2002, with the pipeline operational by the end of 2004. Initial capacity on the pipeline is slated to be 777 billion cubic feet (Bcf) per year, with capacity eventually rising to 1.06 Tcf per year. With natural gas production in the first stage of exploitation of the Shah Deniz field expected to be 282 Bcf per year, the Baku-Erzurum pipeline will have excess capacity to pipe additional Caspian Sea region natural gas exports, possibly from Turkmenistan if the Caspian littoral states agree on a legal regime for the Sea, allowing the proposed Trans-Caspian Gas Pipeline to be built.

Natural gas also could transit Georgia via a proposed north-south pipeline from Russia to eastern Turkey, with one route also passing through Armenia. In November 2000, Georgia approved a project for a 37-mile pipeline to carry Russian natural gas to Turkey via the Georgian Black Sea coast. After a September 2001 meeting, Georgian officials announced that representatives from Conoco and Turkey's Acsoy Group were ready to invest in the pipeline, which would transport 35.3 Bcf per year of natural gas from Kobuleti, Georgia, to Hopa, Turkey.

Georgia also has held discussions with Gazprom on refurbishing the existing North Caucasus-Transcaucasian natural gas pipeline and extending it into a trans-Georgian pipeline to bring Russian natural gas to Armenia and Turkey. However, this idea has lost some support as Russia focuses on delivering its gas to Turkey via the "Blue Stream" natural gas pipeline under the Black Sea.



South, via Iran to Turkey

In December 1997, Turkmenistan launched the $190-million Korpezhe-Kurt Kui pipeline to Iran, the first natural gas export pipeline in Central Asia to bypass Russia. The 124-mile pipeline, which had an initial capacity of 141 Bcf, will have a peak capacity of 282 Bcf per year. In 2000, Turkmenistan exported 106 Bcf to Iran via the pipeline, with that figure increasing to 154 Bcf in 2001.

According to terms of the 25-year contract between the two countries, Turkmenistan will pipe between 177 Bcf and 212 Bcf of natural gas to Iran annually, with 35% of Turkmen supplies allocated as payment for Iran's contribution to building the pipeline. In December 2001, the presidents of Turkmenistan and Armenia reached an agreement by which Turkmenistan will supply up to 70.6 Bcf per year to Armenia via the Korpezhe-Kurt Kui pipeline and across Iran. Implementation of this deal is contingent on the construction of a long-delayed Iran-Armenia natural gas pipeline.Construction of the $120 million, 84-mile Iran-Armenia pipeline link has been delayed for years due to disagreements between the two sides over natural gas prices and the location of the pipeline.

In addition, any large investment in Iran's oil and natural gas sector would be legally problematic. U.S. Presidential Executive Orders signed in 1995 prohibit U.S. companies from conducting business with Iran. Furthermore, the U.S. Iran and Libya Sanctions Act of 1996, which was renewed for five years in August 2001, imposes sanctions on non-U.S. companies that make large investments in the Iranian oil and natural gas sectors.

Southeast, to Pakistan via Afghanistan or Iran

In July 1997, Turkmenistan signed a memorandum of understanding with Afghanistan, Pakistan, and Uzbekistan to build a Central Asia Gas pipeline to carry 0.7 Tcf of natural gas per year via Afghanistan to Pakistan (and possibly on to India). In October 1997, Unocal set up the Central Asian Gas Pipeline (Centgas) consortium to build the pipeline, which would run 900 miles from the Turkmen natural gas deposit at Dauletabad through Kandahar, Afghanistan, and terminate in the Pakistani city of Multan. The pipeline was estimated to cost $2 billion.

However, in June 1998, Russian natural gas giant Gazprom bowed out of the international consortium formed to build the pipeline, and in early August 1998, Unocal announced that Centgas had not secured the financing necessary to begin the work. On August 22, 1998, Unocal suspended construction plans for

the pipeline due to the continuing civil war in Afghanistan and the U.S. missile attacks on suspected terrorist training camps. In April 1999, Pakistan, Turkmenistan and Afghanistan agreed to reactivate the Centgas project, and to ask the Centgas consortium, now led by Saudi Arabia's Delta Oil, to proceed, but continuing fighting in Afghanistan, as well as sanctions imposed by the U.S. and the United Nations on Afghanistan, kept the project on hold.

Until recently, the pipeline was considered effectively dead, but with a fragile peace in Afghanistan established and the Taliban removed from power, the idea of a trans-Afghan pipeline has been revived. Turkmen President Saparmurat Niyazov and Afghan leader Hamid Karzai have expressed their support for the pipeline, and Uzbek President Islam Karimov is also on record advocating the pipeline. In May 2002, Karzai, Niyazov, and Pakistan President Pervez Musharraf held trilateral talks on the pipeline proposal.

Since the Taliban government in Afghanistan was ousted in December 2001 as part of the U.S.-led war on terrorism, this pipeline option has gained some support, but continuing instability in the region may deter potential investors. U.S. Deputy Secretary of State Elizabeth Jones, during a visit to Ashgabat in January 2002, stated that the United States would support private companies that chose to undertake trans-Afghanistan pipeline projects if they were considered to be beneficial and commercially viable.

However, continuing tensions between India and Pakistan make cooperation on a natural gas pipeline highly unlikely for the time being. Although the trans-Afghanistan pipeline could still be built to terminate in Pakistan rather than India, the southeast pipeline option for Caspian natural gas exports remains a distant possibility

Trans-Caspian Western Routes

In order to give Central Asian countries an alternative to exporting their natural gas via the Russian pipeline system, the United States has supported the idea of trans-Caspian pipelines rather than routing pipelines through Iran. The U.S. Trade and Development Agency funded a $750,000 feasibility study by Enron for a natural gas pipeline from Turkmenistan to Azerbaijan, and another feasibility study was also completed by Unocal.

On May 21, 1999, Turkey and Turkmenistan signed a 30-year agreement to ship 565 Bcf/year of Turkmen gas to Turkey, with the rest exported to Europe, starting in 2002. In addition, on November 18, 1999, Azerbaijan, Georgia, Turkey and Turkmenistan signed an Intergovernmental Declaration laying the legal framework for the Trans-Caspian Gas Pipeline (TCGP) route running from Turkmenistan, through Azerbaijan and Georgia, to Turkey.

However, the 1,020-mile TCGP, which is estimated to cost between $2 billion and $3 billion to construct, has been mired in problems, and the future of the project is uncertain. Negotiations between Turkmenistan and the international consortium backing the project have stalled over payment and price issues, and PSG, the co-operator of the project with Royal Dutch/Shell, closed its office in Turkmenistan in October 2000. Also, Azerbaijan and Turkmenistan have been unable to agree on space allocations for the pipeline, which

has a planned capacity of between 565 Bcf and 1.1 Tcf of natural gas.

Turkmenistan had offered Azerbaijan 30% of the pipeline volumes for Azeri natural gas exports, but with the discovery of the Shah Deniz natural gas field in 1999 in Azeri waters, Azerbaijan hardened in its resolve to receive 50% of the available capacity on the pipeline. After negotiations stalled, in March 2001, Azerbaijan consummated a natural gas export deal of its own with Turkey, lowering Turkmenistan's leverage in negotiations over pipeline volumes. In order to supply Turkey with this natural gas, Azerbaijan is proceeding with plans to construct the aforementioned Baku-Erzurum pipeline.

Although Azerbaijan and Turkmenistan resumed talks on the TCGP in October 2001, the lack of a legal framework governing the use of the Caspian Sea continues to complicate the issue of constructing the pipeline. In addition, several of the Caspian littoral states are opposed to trans-Caspian pipelines on environmental grounds. The U.S. continues to support the project in principle, although Stephen Mann, the U.S. Ambassador for Caspian Basin Energy Development, said that Turkmenistan will have to seek the support of private investor companies in order for the project to move forward. Royal Dutch/Shell continues to support the TCGP project.

East, to China

Exxon, Mitsubishi, and China National Petroleum submitted a preliminary feasibility study for the construction of the world's longest natural gas pipeline from Turkmenistan to the Chinese coast, perhaps continuing onwards to Japan. The 1-Tcf capacity pipeline would start in Turkmenistan and traverse Uzbekistan and Kazakhstan before traveling the length of China--a 4,161-mile journey to Xinjiang. The pipeline's estimated cost is $10 billion, which, along with logistical difficulties related to building the longest pipeline, has diminished investor interest in the project.

Natural Gas Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Natural Gas Capacity	Length	Cost Estimate	Status
Baku-Erzurum	Baku (Azerbaijan) via Tbilisi (Georgia) to Erzurum (Turkey), linking with Turkish natural gas pipeline system	Planned 254 Bcf capacity	540 miles	$1 billion (includes up to $500 million to construct new Azeri section)	November 2000 inspection of existing Gazi pipeline deemed that extensive repairs were necessary; new pipeline will be necessary.

"Centgas" (Central Asia Gas)	Daulatabad (Turkmenistan) via Herat (Afghanistan) to Multan (Pakistan). Could extend to India.	700 Bcf/year	870 miles to Multan (additional 400 miles to India)	$2 billion to Pakistan (additional $500 million to India)	Memorandum of Understanding signed by Turkmenistan, Pakistan, Afghanistan, and Uzbekistan. Project stalled.
Central Asia Center Pipeline	Turkmenistan and Uzbekistan via Kazakhstan to Saratov (Russia), linking to Russian natural gas pipeline system	3.5 Tcf/year	Existing route	N/A	Operational. Turkmenistan is using this pipeline to export a total of 8.83 Tcf to Ukraine (via Russia) from 2002 to 2006, as well as smaller amounts to Russia.
China Gas Pipeline	Turkmenistan to Xinjiang (China). Could extend to Japan.	1 Tcf/year	4,1,61 miles; more if to Japan	$10 billion to China; more if to Japan	Preliminary feasibility study done by ExxonMobil, Mitsubishi, and CNPC
Trans-Caspian Gas Pipeline (TCGP)	Turkmenbashy (Turkmenistan) via Baku and Tbilisi to Erzurum, linking with Turkish natural gas pipeline system	565 Bcf in first stage, eventually rising to 1.1 Tcf/year	1,020 miles	$2 billion to $3 billion	Project stalled; negotiations between Turkmenistan and Azerbaijan over pipeline volumes restarted in October 2001.
Korpezhe-Kurt-Kui	Korpezhe (Turkmenistan) to Kurt-Kui (Iran)	283-350 Bcf/year; expansion proposed to 459 Bcf/year by 2005	124 miles	$190 million; 2005 expansion: $300 million to $400 million	Operational since December 1997.

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Greece

Greece is an important potential transit site for energy exports from the Caspian/Caucasus regions, with limited energy reserves of its own.

Note: Information contained in this report is the best available as of August 2002 and is subject to change.

BACKGROUND

Greece is among the smallest of the economies in the European Union (EU), but has enjoyed fairly strong growth over the past few years with relatively low inflation. In 2001, for instance, Greece's real gross domestic product (GDP) grew by an estimated 4.1%, while consumer prices increased at a 3.4% annual rate. For 2002, Greece's real GDP is expected to grow by 2.9%, while its inflation rate is forecast at 2.9%. Greece's unemployment rate has been trending downwards in recent years, from 11.9% in 1999 to 10.4% in 2001. For 2002, unemployment is forecast at 9.9%. Greece hopes to achieve long-term real GDP growth of 5.0%-5.5% over the next 15 years, but outside analysts believe that this is overly optimistic.

Greece's economic growth is being driven in part by infrastructure construction (and foreign investment) for the 2004 Olympic Games, which are to be held in Athens. Also, with Greece joining the "Eurozone" (its 12th member) in January 2001, the general government budget experienced a surplus in 2001 for the first time in over three decades, while interest rates have declined sharply. Meanwhile, since the mid-1990s, Greece has embarked on a series of macroeconomic and structural reforms, including measures aimed at slashing bureaucracy and at attracting foreign investment. The International Monetary Fund (IMF) and OECD both have called for continued efforts in these areas.

Relations between Greece and Turkey have improved recently, allowing for discussion of economic and energy cooperation. In March 2002, Greece and Turkey began discussions on resolving a decades-long disagreement over Aegean Sea boundaries. The two countries also are increasing cooperation in the economic and energy areas (see below). Greece is a major investor in the former Yugoslavia and its energy infrastructure is being integrated with that of the Balkan states. Improved relations with neighboring states could help Greece significantly in achieving its ambitious goal of becoming the major Balkan energy (oil, natural gas, electricity) hub by 2010 (at a cost of up to $14.5 billion).

OIL

Greece has limited oil reserves of 9 million barrels. The country produces 8,992 barrels per day (bbl/d) and is highly import reliant for its 406,000 bbl/d oil consumption (2001 estimate). Oil is Greece's most important fuel source, accounting for 63% of total energy consumption in 2000, a percentage that has remained fairly stable since the mid-1980s. Oil is imported primarily from Iran, Saudi Arabia, Russia, Libya and Egypt. The Middle East is expected to remain the major source of Greek oil supplies in coming years, although Russia could become more important as new pipelines are constructed.

Greece's oil industry is dominated by state-owned Hellenic Petroleum (HP), which was formed in 1998 from the former state oil company, Public Petroleum Corporation (DEP). HP conducts oil exploration, imports crude and products, operates three large refineries (one in Macedonia), and distributes and markets oil products. HP has been partially privatized in stages, with the state holding 60.1% at year-end 2000. HP's initial public offering (IPO) was in June 1998, when 23% of the company was sold, to a mixture of retail and institutional investors. In August 2001, the Greek government announced its intention to sell another 30% of HP. In July 2002, the Greek government announced that the sale of a 23.17% stake in HP should be completed by the end of August 2002. A joint venture between Russia's Lukoil and Greece's Latsis Group - which owns Greece's third-largest

refiner Petrola - has offered to pay $459 million for the stake (in June 2002, Russia's Yukos and Austria's OMV withdrew from the bidding). In early July 2002, a 15-day strike at HP by workers opposed to HP's privatization came to an end after a Greek court ruled that the strike was illegal.

Greece's oil production comes from the Prinos area in the Aegean Sea, off the coast of Kavala. The Prinos fields, which began production in 1996, are operated by the U.S., Greek, and Canadian North Aegean Petroleum Company (NAPC) consortium. In February 2001, a new oilfield was found offshore the Aegean island of Thasos (also near Kavala) by Kavala Oil, with production expected to be 7,000-7,500 bbl/d. The oil will be sold to HP for refining.

Greece's first oil exploration licensing round was held in 1996 and awarded six concessions. In May 2002, Greece announced that it would hold its second oil exploration licensing by early 2003. The round is to include both offshore and onshore areas in northwestern and southwestern Greece, plus unexplored blocks in the Ionian Sea. Exploration in the Aegean Sea is complicated by lack of agreement between Greece and Turkey delineating continental shelf boundaries.

HP is developing a $100-million, 143-mile pipeline to carry crude oil from the northern port city of Thessaloniki to HP's newly-acquired Okta refinery near Skopje, in the Former Yugoslav Republic of Macedonia (FYROM). Construction of the pipeline by HP's subsidiary El Pet Balkaniki began in November 1999. This pipeline will have the capacity to carry about 50,200 bbl/d. The pipeline will be managed in partnership with the FYROM, and will carry crude that currently is shipped by rail from Thessaloniki to Okta.

In January 1997, Greece, Bulgaria and Russia agreed on a plan to build an oil pipeline linking the Bulgarian Black Sea port of Burgas with Alexandropoulis on the Mediterranean coast of Greece. The proposed 178-mile, underground, Trans Balkan pipeline would allow Russia to export oil through the Black Sea while bypassing Turkey's Bosporus and Dardanelles Straits. However, the

$600-$800 million project has been stalled by a wide range of technical and economic disputes. Russia has affirmed that the pipeline, with proposed capacity ranging from 600,000 bbl/d to 800,000 bbl/d, will work at least at 50% of its capacity, and Russian oil major Yukos has expressed its interest in the project, which may ease concerns over filling the pipeline. Greece also has discussed with Kazakhstan the possibility of shipping oil through the pipeline. In May 2002, Bulgaria said that it hoped an agreement on the pipeline could be signed by the end of 2002, with the main outstanding issue being the percent stake that each country will take in the project.

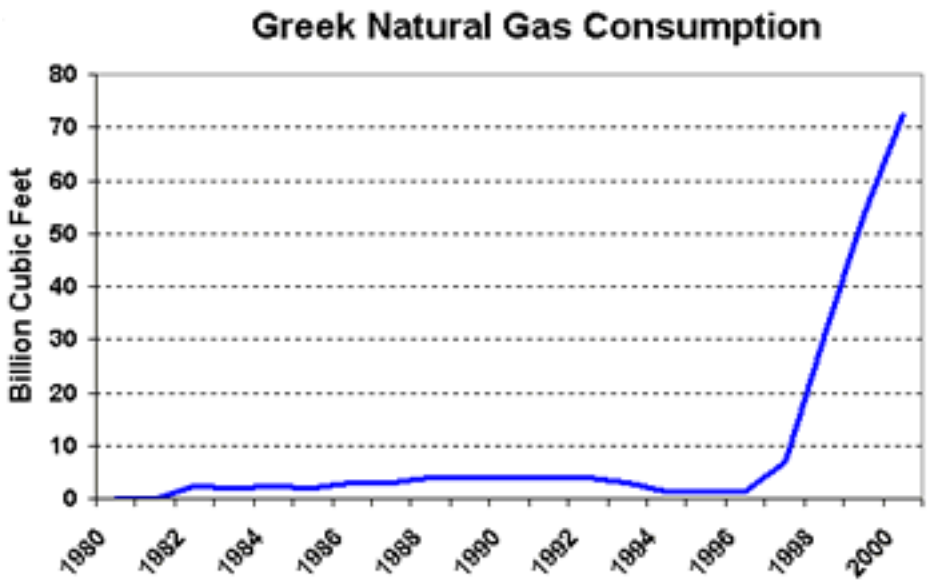
Downstream

HP owns about half of Greek refining capacity, which totalled 406,500 bbl/d as of January 1, 2002. HP's Aspropyrgos facility refines about 140,000 bbl/d, while the Thessaloniki refinery has a 66,500-bbl/d capacity. Two private refineries, owned by Motor Oil Corinth Refineries and Petrola Hellas, are export-oriented, selling only limited volumes to the national market. Motor Oil, which had been majority-owned by Saudi Aramco, was partially sold off to Petroventure of Jersey in July 2001, a joint venture of Aramco and Vardinoyannis, which separately each own 16.4% of Motor Oil.

HP also is the largest player in the Greek retail oil market at a 26% market share. U.S.-based Texaco and British-Dutch Royal Dutch/Shell decided in 2000 to trade Texaco's Greek retail assets for some of Shell's United Kingdom retail assets.

NATURAL GAS

With natural gas reserves of only 18 billion cubic feet (Bcf), Greece produces negligible amounts of natural gas. Consumption, however, has increased significantly over the past few years, increasing from only 1 billion cubic feet (Bcf) in 1996 to 72 Bcf in 2000. Consumption is expected to continue increasing, possibly tripling over the next ten years. About 80% of Greece's natural gas imports currently come from Russia, and 20% from Algeria.



The Greek natural gas industry is controlled by the state-owned Greek Public Gas Company (DEPA), which was created in 1988 in an attempt to diversify the primary energy supply by increasing the role of natural gas. DEPA is 35% owned by HP, with the Greek government owning the rest. In April 2002, plans were announced to sell off 35% of the government's share of DEPA, with possible buyers including Russia's Gazprom, Germany's Ruhrgas, and Algeria's Sonatrach. Eventually, the plan is for DEPA to be only minority-owned by the state.

DEPA began importing natural gas from Russia via Bulgaria in July 1997 through a Bulgarian pipeline (Greece's only operational gas pipeline), and the company has contracts to supply natural gas to electric utilities and industrial companies. In March 2001, DEPA and Gazexport (part of Gazprom of Russia) agreed on an importation deal for 2002 which includes a 5% price increase. Under the EU Gas Directive, 20% of Greece's natural gas market was to have been opened to competition by August 2000, but Greece was granted extra time. Under current Greek law, companies other than DEPA can only import gas to generate electric power destined for export.

Recent improvements in Greek-Turkish relations are facilitating discussions of energy cooperation. For instance, Greece and Turkey agreed in July 2000 to work together to develop connections between their natural gas networks. This commitment was reaffirmed at "The EU and Black Sea economic cooperation conference" in September 2001 by the Turkish officials at the conference. Senior Greek and Turkish officials have signed an agreement at EU headquarters to study how best to develop natural gas connections. The two countries have agreed to work with the EU-sponsored Interstate Oil Gas

Transport to Europe (INOGATE) project, which provides technical assistance to modernize oil and gas transport in central Europe and Asia in order to work toward European pipeline linkage to Caucaus and Asian oil and gas. In March 2001, Greece signed an agreement with Armenia and Iran to strengthen economic and energy cooperation. Discussions included the possibility of an EU-subsidized natural gas pipeline from Iran through either Armenia and Ukraine or Turkey and Greece.

Greece received its first liquefied natural gas (LNG) shipment in November 1999, beginning a 21-year contractual agreement between Algeria and Greece under which DEPA will purchase gas from Algeria's Sonatrach. Greece has one LNG terminal at Revithoussa, near Athens, with a capacity of 23 Bcf per year. A feasibility study is underway to determine whether to construct an underwater gas pipeline connecting Italy and Greece; if this pipeline does not come to fruition, it is possible that another LNG terminal will be constructed in Greece or that the terminal at Revithoussa will be expanded.

On December 15, 1997, Russia and Turkey signed a 25-year deal under which the Russian gas company, Gazprom, would construct a new natural gas export pipeline (called "Blue Stream") to Turkey for delivery capacity of around 565 Bcf annually, with initial deliveries possibly starting in 2002. The $3 billion, 758-mile dual pipeline is slated to run from Izobilnoye in southern Russia, to Dzhugba on the Black Sea, then under the Black Sea for about 247 miles to the Turkish port of Samsun, and on to Ankara. Natural gas supplies through the Blue Stream pipeline are slated to begin in October 2002, with Russia scheduled to deliver 70.6 Bcf of natural gas to Turkey via the pipeline this year. By 2009, Blue Stream is expected to reach peak capacity of 565 Bcf per year. Over the course of the 25-year agreement, Turkey will import 14.1 Tcf of natural gas from Russia via Blue Stream. Eventually, the Blue Stream project could be extended onwards to other Mediterranean countries, including Greece.

Along these lines, Greece and Turkey signed an agreement on March 28, 2002 which calls for extending the natural gas pipeline from Iran to Turkey

into Greece. Reportedly, the 175-mile-long pipeline (125 miles in Turkey, 50 miles in Greece), expected to be completed by 2005, would connect Ankara to Alexandroupolis in northern Greece at a cost $300 million. The pipeline initially will transport around 17.7 Bcf of natural gas per year. Eventually, natural gas could be transported to Europe via Bulgaria or via an undersea pipeline to Italy, where gas demand -- especially for electric power generation -- is expected to grow rapidly in coming years. A deep water option could be extremely expensive, however, making an overland route more likely. Also, in April 2002, Azerbaijan said that it could start supplying Greece with natural gas in 2006-2007 through the Baku-Tbilisi-Erzurum pipeline and the Turkey-Greece pipeline extension.

COAL

Lignite ("brown coal"), a brownish-black coal of low quality used almost exclusively for steam-electric power generation, is Greece's only significant fossil fuel source. Greece's lignite reserves total 3,168 million short tons (Mmst). The largest deposits are at Ptolemais and Amintaio, in northern Greece. The country has no hard coal reserves, and imports hard coal from South Africa, Russia, Venezuela, and Colombia. Domestic production has been partly opened to private companies, but the Public Power corporation is still the largest producer, as well as consumer.

ELECTRICITY

In 2000, Greece generated 49.6 billion kilowatthours (Bkwh) of electricity, around 90% of which was thermal, 10% hydropower, and 1% solar (percentages do not equal 100% due to rounding). Most of the thermal is lignite-fired, with some oil-fired plants. New plants will be gas-fired for the most part. Electricity demand has been growing steadily -- around 3.4% per year -- meaning (according to the Energy Regulatory Authority, RAE) that some 6,000 megawatts (MW) of additional capacity will be needed to guarantee supply through 2015. Greek authorities are concerned that electrical generation capacity will be insufficient for the 2004 Olympic Games in Athens. Natural gas will become an important fuel for electricity generation as planned gas-fired plants are constructed.

Greece's Public Power Corporation (I.PPC) is a state-owned monopoly that controls electric production, transmission, and distribution in the country. A flotation of 10%-15% of I.PPC is planned by the end of 2002. In February 2001, with the partial liberalization of Greece's power market (35% was opened to competition) in accordance with the EU's Electricity Directive, I.PPC lost its legal monopoly on electricity generation but remains the sole distributor. Other EU member countries had to open up their electricity markets by February 1999, but Greece was granted a two-year waiver in recognition of its unique situation: it borders no other member state, and much of its territory is comprised of islands that cannot be linked into the national grid. Given the lead time on construction of new power plants, it will be a while before competing generators are functioning, so I.PPC still has an effective production monopoly. The OECD has urged Greece to break up I.PPC, and plans are for the Greek power sector to be completely liberalized by 2005. Management of the Greek power liberalization process is the responsibility of RAE, the Greek regulating authority.

Greece's power network currently is connected with the networks of Albania, the Former Yugoslav Republic of Macedonia (FYROM), and Bulgaria, allowing Greece to export electricity to Kosovo in Yugoslavia, through Albania and FYROM (although transmission problems in those countries have sometimes prevented much of this electricity from reaching its intended recipients). In June 2001, energy ministers from Albania, Bosnia and Herzegovina, Bulgaria, Greece, FYROM, and Romania signed a memorandum for the creation of a competitive energy market in the Balkans. Greece would like to upgrade its link with Bulgaria and to Europe via Croatia and Bosnia. Greece is involved in a number of projects to link its electric grid with neighboring countries. In July 2002, Greece and Italy completed work on a 500-megawatt (MW) cable (in both directions) under the Ionian Sea to link their national power grids. The 102-mile cable links Otranto, Italy, and Aetos, Greece. The project is a joint venture between ENEL (75%) and PPC (25%).

Improved Greek-Turkish relations also are affecting the Greek electricity sector. In January 2000, a Greek-Turkish-U.S. (Copelouzos-Gama-ExxonMobil) consortium announced plans to construct a gas-fired power plant in Greece. The plant will have a capacity between 400 MW and 600 MW and will be used to export electricity to Turkey in addition to helping supply increasing Greek domestic demand. Electricity will be exported via the new 400-kilovolt (kV) transmission line to be constructed between Filippoi (Greece) and Hamidabad (Turkey). Greece and Turkey also hope to reach agreement by 2006 on linking the two countries' power grids.

Renewable electricity generation projects are on the rise in Greece, and the government has established the Centre for Renewable Energy Sources (CRES), under the Development Ministry, to promote renewable energy. CRES estimates that 15% of the country's electricity needs can be produced by wind farms, with installed wind-power capacity possibly expanding from 270 MW at present to 2,000 MW by 2010. The EU requires that member states produce 12% of their electricity from renewable sources by 2010, and this appears easily achievable for Greece -- assuming that regulatory hurdles and technical problems (i.e., the need to extend Greece's power grid to the islands where wind power is generated) can be overcome. Already, wind farms exist on a number of Greek islands (Crete, Evia, Andros, Samos, etc.) and 20% of households use solar water heaters. Islands in the western part of Greece are connected to the mainland system by submarine cables.

The use of solar power in Greece reduces the need for conventionally generated energy by about 1.4 billion kilowatthours per year. A 50-MW parabolic trough-type solar power plant is under construction in Crete. DEH is planning a 100-kilowatt photovoltaic (PV) park for Gavdos island, in addition to already-existing PV capability on the island. Energy Photovoltaics (a German-Italian-American consortium) announced in July 2001 that it will build a $22 million solar plant in Kilkis with power generation capacity of 5 MW.

In February 2002, a report by Merrill Lynch estimated that wind power

capacity additions in Greece would be 26 MW in 2002, 19 MW in 2003, 54 MW in 2004, and 56 MW in both 2005 and 2006. In June 2001, Gemesa of Spain signed an agreement with Hellenic Energy and Development Company to invest 420 million euros to develop wind power plants with a total capacity of 460 MW by 2005. Windforce of the UK plans to develop $800 million of projects in the EU, including three wind farms in Greece (at Makronisos, Kilkis, and Lakonia) with a total capacity of 650 MW.

COUNTRY OVERVIEW

President: Konstantinos "Kostis" Stephanopoulos; since May 5, 1995
Prime Minister: Konstandinos Simitis (Panhellenic Socialist Movement - Pasok); since January 19, 1996
Independence: 1829 (from the Ottoman Empire)
Population (7/01E): 10.6 million
Location/Size: Southern Europe, bordering the Aegean, Ionian and Mediterranean Seas/131,940 sq. km. (51,146 sq. mi) ; roughly the size of Alabama
Major Cities: Athens (capital), Thessaloniki, Piraeus, Patras
Languages: Greek (official), English, French
Ethnic Groups: Greek (98%); other (2%)
Religion: Greek Orthodox (98%), Muslim (1.3%), other (0.7%)
Defense (8/98): Army (116,000), Navy (19,500), Air Force (33,000), Conscripts (112,700)

ECONOMIC OVERVIEW

National Economy and Finance Minister: Nikos Khristodoulakis
Currency: Euro
Market Exchange Rate (8/8/02): US$1 = 1.026 Euro
Nominal Gross Domestic Product (GDP, 2000E): $113 billion
Real GDP Growth Rate (2001E): 4.1% **(2002F)**: 3.8%
Unemployment Rate (2000E): 11.4% **(2001F)**: 10.7%
Inflation Rate (2001E): 3.4% **(2002F)**: 2.9%
Major Trading Partners: Germany, Italy, other OECD Europe
Major Export Products: Manufactures, food and beverages, petroleum

products
Major Import Products: Manufactured consumer goods, capital goods, crude oil, food products
Merchandise Exports (2000E): $15.8 billion (half to the EU, 6% to the US)
Merchandise Imports (2000E): $33.9 billion (two-thirds from the EU)
Current Account Deficit as a % of GDP (2001E): -6.2% **(2002F)**: -7.8%
External Debt (2000E): $57 billion

ENERGY OVERVIEW

Minister of Development: Apostolos-Athanasios Tsokhatzopoulos
Proven Oil Reserves (1/1/02E): 9 million barrels
Oil Production (2001E): 8,992 barrels per day (bbl/d), of which 4,992 bbl/d is crude oil
Oil Consumption (2001E): 406,000 bbl/d
Net Oil Imports (2001E): 397,008 bbl/d
Crude Oil Refining Capacity (1/1/02E): 406,500 bbl/d
Major Crude Oil Import Sources: Persian Gulf OPEC
Natural Gas Reserves (1/1/02E): 18 billion cubic feet (Bcf)
Natural Gas Production (2000E): 0.1 Bcf
Natural Gas Consumption (2000E): 72 Bcf
Coal Reserves (2000E): 3,168 million short tons (all lignite)
Coal Production (1999E): 67.2 million short tons (Mmst)
Coal Consumption (2000E): 70.5 Mmst
Electric Generation Capacity (2000E): 10.1 gigawatts
Electricity Production (2000E): 49.6 billion kilowatthours (Bkwh)

ENVIRONMENTAL OVERVIEW

Minister of Environment, Town Planning, Public Works: Vasso Papandreou
Total Energy Consumption (2000E): 1.3 quadrillion Btu* (0.3% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 26.8 million metric tons of carbon (0.4% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 126.1 million Btu (vs U.S. value

of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 2.5 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 9,653 Btu/ $1995 (vs U.S. value of 10,918 Btu/ $1995)**
Carbon Intensity (2000E): 0.19 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (1998E): Industrial (34.5%), Transportation (35.2%), Residential (20.9%), Commercial (9.4%)
Sectoral Share of Carbon Emissions (1998E): Industrial (39.2%), Transportation (27.5%), Residential (21.5%), Commercial (11.8%)
Fuel Share of Energy Consumption (2000E): Oil (63.2%), Coal (27.8%), Natural Gas (6.0%)
Fuel Share of Carbon Emissions (1999E): Oil (60.2%), Coal (36.8%), Natural Gas (3.0%)
Renewable Energy Consumption (1998E): 93 trillion Btu* (2% decrease from 1997)
Number of People per Motor Vehicle (1998): 3.1 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified August 4th, 1994). Under the negotiated Kyoto Protocol (signed on April 29th, 1998, ratified along with EU in May 2002), Greece has agreed to limit greenhouse gas increase to 25% above 1990 levels by the 2008-2012 commitment period. Within the EU, each country has a different commitment.
Major Environmental Issues: Air pollution and water pollution.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94 and Wetlands. Has signed, but not ratified, Air Pollution-Persistent

Organic Pollutants, Air Pollution-Volatile Organic Compounds.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 2000.

OIL AND GAS INDUSTRIES

Organization: Hellenic Petroleum -- the state petroleum company; DEPA -- the state-controlled gas company; Public Power Corporation - the state-owned utility
Major Refineries (capacity - bbl/d, 1/1/02E): HP Aspropyrgos (140,000), Motor Oil Aghii Theodori (100,000), Petrolas Hellas Elefsis (100,000), HP Thessaloniki (66,500)
Major Ports: Piraeus,Thessaloniki, Patras

Sources for this report include: CIA World Factbook 2000; Dow Jones News wire service; Economist Intelligence Unit ViewsWire; Financial Times; Oil and Gas Journal; Petroleum Economist; International Market Insight Reports; DRI/WEFA, Global Power Report; CNN Interactive; National Trade Data Bank; Petroleum Intelligence Weekly; U.S. Energy Information Administration; World Markets Energy.

LINKS

For more information on Greece, see these other sources on the EIA web site:
EIA Data for Greece
European Union Fact Sheet

Links to U.S. government other sites:
CIA World Factbook, Greece
U.S. Department of Energy's Office of Fossil Energy's International section, Greece
U.S. Department of State Consular Information Sheet, Greece
U.S. Embassy and U.S. Information Agency, Athens, Greece

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The Greek Connection
Greek Government online
Greek Government information
European Regional Development Fund and Cohesion Fund
European Commission Directorate General for Energy and Transport
European Commission Directorate General for Environment
European Commission Directorate General for the Internal Market
EU Council, Economic Policy Coordination
International Energy Agency 1998 review of Greece
Hellenic Petroleum (HP)

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January 2002

France

France is one of the world's largest nuclear power producers, but has very limited fossil fuel resources. The 1999 merger of its top two oil companies formed the fourth largest oil company in the world.

The information in this report is the best available as of January 2002 and is subject to change.

BACKGROUND

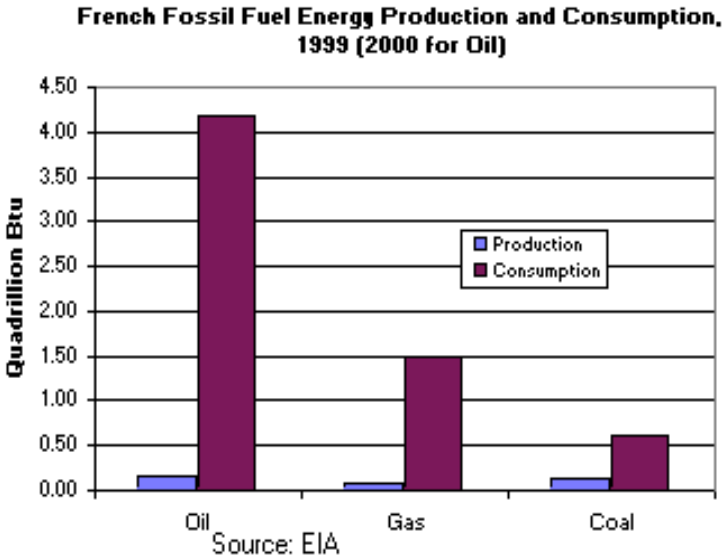
One of the world's largest economies, France is a founding member of the European Union (EU) and a member of the Group of Seven (G-7) industrialized nations, the General Agreement on Tariffs and Trade (GATT)/World Trade Organization (WTO), the International Energy Agency (IEA), and the International Atomic Energy Agency (IAEA). France joined the common European currency, the euro, on January 1, 1999. France's economy has had stronger growth than that of many of its neighbors in recent years, having experienced a cyclical upturn since late 1997 that is now winding down. France's economy grew 3.4% in 2000, but growth is estimated to have declined to 2.1% in 2001. France's economy in 2002 will closely track the eurozone as whole, where growth for 2002 is forecast at 1.4%. Euro coins and bills were introduced beginning January 1, 2002, though the French franc has been pegged to the euro since 1999.

Traditionally, the role of the state has been stronger in France than in other Western European countries. France is one of the most centralized countries in Europe with a strong history of state ownership in the aviation, telecommunications, and energy industries. However, the role of the government now is changing. Important economic and political changes in France include widespread privatization and increasingly frequent mergers and acquisitions (M&As) and hostile corporate takeovers, once virtually unheard of in France.

International pressures of globalization and more direct pressure from the EU are behind the current trend away from government involvement in industry. The French government is headed by the moderate socialist prime minister, Lionel Jospin, and the Gaullist president, Jacques Chirac, under the French system of governmental "cohabitation." The divided government has moved very slowly toward privatization of the country's energy industry, despite an EU directive that calls for member states to relinquish control of their energy companies to the private sector. This has caused friction between France and other EU members, particularly in regard to acquisitions by Electricite de France (EdF).

ENERGY

French energy policy has been relatively consistent in recent decades, with the main objectives including: securing energy supply, achieving international competitiveness, and protecting the environment. The focus on energy security has led France to become one of the world's top producers and consumers of nuclear power. France's production of primary energy rose by 2.1% in 2000, to about 5.04 quadrillion Btu. France's energy demand rose by 1.1% to about 10.3 quadrillion Btu. However, France's total energy bill rose by 102% in 2000, to 155.2 billion French francs (FFR).



OIL

About 1.9 million barrels per day (bbl/d) of France's approximate 2 million bbl/d oil consumption are imported. France has reserves totaling only 140 million barrels. Exploration increased in 2000-2001 because of higher oil prices, and France's proven reserves increased in 2000, though they are still extremely small, and fell slightly in 2001. France's domestic crude oil production comes from numerous wells producing very small amounts of oil. Because of France's limited domestic fossil fuel energy sources, security of supply historically has been a major concern.

Despite France's limited domestic reserves and production, the French oil industry is an important actor in world energy markets. Major oil assets of French oil companies are located in the North Sea, Africa, and Latin America. French imports come primarily from Saudi Arabia and Norway, followed by the United Kingdom (UK), Iraq, Iran, Nigeria, and Russia. In July 2001, the Iraqi government stated that it would reconsider oil projects with French companies and no longer give French companies "priority" due to France's support of the U.S.-British "Smart Sanctions" proposal at the United Nations Security Council. Iraq has letters of intent with TotalFinaElf that would take effect when sanctions are lifted.

In early 1999, French oil company Total merged with Belgian oil company Petrofina to create TotalFina, the world's sixth-largest oil company and the third-largest oil company in Europe. Only months later, TotalFinaElf was formed by TotalFina's acquisition of Elf Aquitaine. After the deal was completed in 2000, TotalFinaElf became the fourth-largest publicly listed oil company in the world, after ExxonMobil, Royal Dutch/Shell, and BP. TotalFinaElf has proven reserves of about 10.8 billion barrels of oil equivalent and production of about 2.1 million bbl/d. TotalFinaElf has very little crude oil production in North America or Asia (outside of the Middle East), unlike the other super majors. The company claims to have raised hydrocarbon output by 6% in 2001 and plans to raise production by 9% in 2002 as major new resources come on stream. TotalFinaElf owns more than 50% of the refinery capacity in France, and is the seventh-largest refiner in the world.

Downstream

France's crude oil refining capacity is 1.9 million bbl/d. The country's largest refinery is TotalFinaElf's refinery at Gonfreville l'Orcher with a capacity of 323,643 bbl/d. Increasingly strict EU environmental

regulations for refineries are in large measure behind recent upgrades in the French refining sector. The regulations will become considerably more strict in 2005, and substantial investment in the refining sector will be necessary to meet these new mandatory targets. ExxonMobil has begun adapting its Port Jerome refinery to 2005 EU specifications.

Because oil security has been such a concern for French energy policy-makers, there is a French law allowing the French government to refuse to close a refinery if it believes its supply or price security is at risk. Essentially, this gives the French government veto power over EU legislation regarding refineries. This could become an important issue as the EU's environmental standards are strengthened further.

NATURAL GAS

France has very limited natural gas resources and therefore imports almost all of the natural gas it consumes. Natural gas consumption increased 3.6% in 2000, and the share of natural gas in the French energy market rose to 14.5%. Industry's share of consumption rose from 44% to 48% year-on-year 1999-2000, but household use declined from a 39% share to a 36% share year-on-year 1999-2000.

The French natural gas industry is run by Gaz de France (GdF), the state-held company with a monopoly on importation and distribution of natural gas in France. By 2003, Gaz de France aims to possess sufficient reserves to produce at least 15% of the natural gas it sells. The company's annual production capacity stands at more than 70 billion cubic feet (Bcf). GdF also has the largest underground storage capacity in western Europe, with 318 Bcf, about 3 months supply. In November 2001, the French government decided to privatize the country's natural gas transport network, allowing the operators, GdF and a subsidiary of TotalFinaElf, to purchase it. However, Communist members of parliament blocked the plan in December, though it seems likely that a version will take effect sometime in 2002. France is the only EU country that owns a franchised natural gas network. GdF has increased substantially its holdings in North Sea natural gas over the past few years, including interests in Norway's Snoehvit and Njord fields. The company acquired holdings in twelve exploration licences in the UK North Sea with an average equity of 21% from Texaco in June 2001. GdF supplies about a fifth of total French consumption from its holdings in France and abroad. Norway is France's top natural gas imports supplier, followed by Russia and Algeria. Natural gas imports from Russia have been declining in recent years, while imports from Algeria have been rising. However, there has been discussion of a new pipeline to connect Russian natural gas to France. The Netherlands is a smaller source of French natural gas imports. GdF also imports liquefied natural gas (LNG) to its two terminals. In addition to long-term contracts, GdF buys natural gas on the spot market or with short-term contracts from the UK's North Sea.

France is the only country in the EU that has not yet enacted any legislation adopting the rules of the EU's 1998 Gas Directive. However, there have been some changes in France's natural gas market since 1998. The EU directive required that 20% of member countries' natural gas markets become competitive. Without a legal basis, GdF nonetheless opened its grid to third-party access in August 2000. About 100 of the country's largest industrial consumers now are able to choose their suppliers. The companies allowed to choose other suppliers and use GdF's network are limited to 20% of the market, the minimum prescribed in the directive. However, no progress has yet been made on plans to change the status of GdF from a wholly-owned state enterprise to a joint stock company, that could then be partially privatized. Because France has been one of the slower countries to pave the way for competition, it has come under harsh criticism from the EU and fellow member countries. In September 2000, the European Commission (EC, the executive body of the EU) sent a formal warning letter to France for failure to notify the EC of national laws enacted to ensure implementation of the 1998 Natural Gas Directive. Although France adopted draft legislation in May 2000, the full national parliament has not yet passed a law to open the market, and is not likely to do so until after the parliamentary and presidential elections in the spring of 2002.

GdF is establishing France as a hub for Western European natural gas. In October 1998, France for the first time became linked via pipeline to a foreign production field. The NorFra pipeline linked Norway's Troll gas field in the North Sea to the French natural gas grid. The pipeline is 840 kilometers (521 miles) long, and is the longest undersea natural gas pipeline in the world. About half of the natural gas from the pipeline will transit through France to points in Italy and Spain, while the other half will be consumed in France. By

2005, the Norwegian pipeline is expected to supply one-third of France's total natural gas consumption. GdF is increasing its trading activities in partnership with Societe Generale, a French Bank. GdF's trading affiliate, Gaselys, carried out 600 transactions in 2000, six times the volume of 1999. GdF has invested abroad heavily, and owns distribution networks in several countries. However, France's lack of liberalization may cause problems with GdF's business in other EU countries. In 2001, Spain's Enagas refused access to its pipelines to GdF on the grounds that there is a "lack of reciprocity with France." In addition, this has prevented GdF from entering partnerships that have cross-ownership with foreign companies, such as Statoil.

GdF is constructing the Les Marches du Nord-Est pipeline in two parts. The first 124-mile part went operational in October 2001, and the second 186-mile part is expected to go operational in October 2002. GdF has signed a 25-year contract with Italy's Snam for delivery of 6 billion cubic meters (Bcm, or 212 Bcf) of Norwegian natural gas through the pipeline. GdF plans to spend $2.5 billion 2001-2003 on developing its pipeline network and installations in France.

Liquefied Natural Gas

GdF has two liquefied natural gas (LNG) terminals: the 159-Bcf-per-year capacity facility at Fos-sur-Mer near Marseille and the 353-Bcf-per-year capacity facility at Montoir-de-Bretagne, near Nantes. Increasing France's importance as a transit center, GdF receives Nigerian LNG at its Montoir-de-Bretagne terminal that is swapped out to Italy's Enel. The terminal receives 4 Bcm (141 Bcf) annually, 3.5 Bcm (124 Bcf) under the Italian contract and 0.5 Bcm (18 Bcf) under a contract signed by GdF.

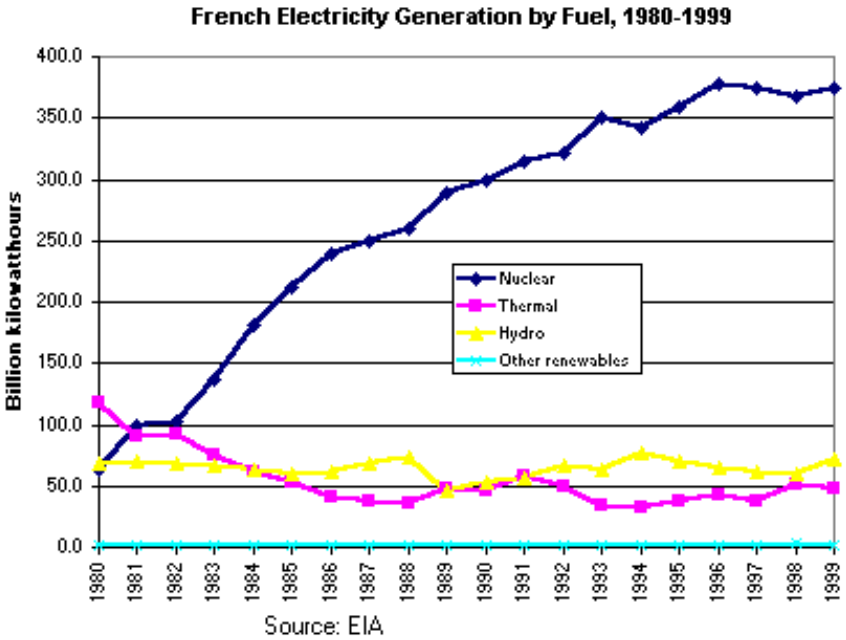
COAL

France has very limited coal reserves and neither produces nor consumes significant amounts of coal. Coal-fired electricity has been mostly replaced by nuclear power. Coal imports come from Australia, the United States, and South Africa.

The French government has supported the coal industry since the 1994 National Coal Pact between Charbonnages de France (CdF), the state coal company, and French coal miners unions. According to the agreement, the industry would receive state support as it gradually phased out the industry all together. All French coal mines are slated to be shut down by 2005. In May 2001, the EC authorized France to pay EUR 991 million in state aid to the coal industry. The number of mine workers is to have been reduced to 2,800 at the end of 2001 and production to just 2.2 million short tons, according to the government's plan.

ELECTRICITY

France is the second-largest electricity market in Europe (behind Germany). France's electricity sector is dominated by the state-held monopolist, Electricite de France (EdF), which produces, transports, and distributes over 95% of electricity in France. EdF is the last major state-run electricity monopolist in the EU, as most of France's neighbors have privatized their electricity companies. However, there has been partial liberalization of some aspects of France's electricity sector.



A 1996 EU directive required that at least 26% of electricity sales in member counties be opened to competition, beginning in February 1999. This requirement increased to 28% in February 2000 and will

increase further to 33% in 2003. In February 2000, a full year after the first EU deadline, France passed legislation that began the electricity sector's liberalization. Since that time, about 1,800 large industrial and commercial consumers (those using more than 16 million kilowatthours per year) comprising about 30% of the market have been able to choose their electricity supplier (although few of these consumers actually have changed suppliers). There has been criticism that the February 2000 law's requirement of three-year contracts is an obstacle to the real establishment of a free market.

Another step toward liberalization has been the creation of the Electricity Transmission Network (Reseau de Transport d'Electricite, RTE) that owns the country's high tension transmission network. RTE's mission is to assure all clients fair access to the network. The single tariff for international electricity transport proposed by RTE was given a positive reception by the European council of energy ministers in May 2001. In addition, an energy regulatory body has been established to oversee the deregulation process. The Commission for the Regulation of Electricity (CRE), which also will oversee natural gas deregulation when the time comes, has four main purposes: (1) advising the government in nearly all matters relating to electricity, (2) the close monitoring of the rules governing the access to the networks and compliance therewith, (3) the auditing of EdF's unbundled accounts, and (4) sanctions against infringements in certain cases, mainly in relation to network access. CRE is gradually taking on more responsibility as liberalization continues.

In late November 2001, the Powernext electricity trading market was launched in France. Powernext auctions standard hourly contracts for physical delivery of electricity to business customers under responsibility of the RTE and guaranteed by Clearnet, a subsidiary of the Euronext stock exchange. Powernext aims to trade 10% of the French market by 2003-2004, and also to act as a price reference for the electricity market. In an additional liberalizing step, in accordance with the terms of EdF's acquisition of a controlling stake in Germany's EnBW, EdF sold 1200 megawatts (MW) of virtual power capacity to some 20 competitors (generators, traders, etc.), French and foreign, in 2001.

There are currently only two companies of any size in France that may be able to compete on a limited basis with EdF in the future. France's second-largest electricity group is Compagnie Nationale de Rhone (CNR), which produces about 3% of France's electricity, mostly from hydroelectric plants. In August 2001, a company for the commercialization of CNR's production was created by CNR and Electrabel of Belgium that is called Energie du Rhone. It will also market electricity produced by Electrabel. The French government has made EdF divest itself from its small holding in CNR in an effort to liberalize the market. The other producer is SNET, a subsidiary of French coal utility Charbonnages de France. In an effort to get into the French market, ENDESA of Spain has purchased about 30% of SNET. Because of interconnectors, other foreign companies are also attempting to get a foothold in the French electricity market. So far, EnBW (34.5% owned by EdF) and RWE, both of Germany, have attracted a small amount of industrial customers.

EdF has come under criticism and scrutiny from member EU countries, the European Comission (EC), and others on several counts. One is that liberalization around the world, and in the EU in particular, has made many electricity assets available abroad while EdF's assets (which are about 95% of the market) are unavailable. Hence, EdF can purchase foreign companies, but foreign companies cannot purchase assets in France. Another charge is that EdF's status as a state-owned monopoly has made it easier for it to purchase and outbid competitors abroad. EdF allegedly enjoys a lower cost of capital than private-sector rivals and a management that can focus on expansion rather than domestic competitors. In addition, it is alleged that taxpayers finance the expansion while the company does not have to justify its expansion to shareholders as would be necessary in a private sector company. In June 2001, the EC launched an investigation into EdF to see whether the company has benefitted from illegal state aid such as tax breaks or certain financial guarantees.

In any event, EdF has made many large foreign purchases in the past few years, such that 25% of EdF's 2000 revenues of EUR 34.4 billion came from assets in 19 foreign countries. The contract between the French government and EdF for 2001-2003 plans for EUR 19 billion in purchases abroad by 2005. In response, Spain and Italy passed laws or adopted regulations that make it difficult for EdF to purchase their

electricity assets. Spain compromised October by allowing the takeover of part of Hidrocantabrico in return for France increasing the interconnection between the two countries from 1,000 MW to 4,000 MW by 2006. In terms of Italy's law, the EC ruled in June 2001, that capital flows may not be restricted merely because of varying degrees of liberalization. However, the initial privatization sale may be restricted, but such restrictions can only be in place for a limited period, after which the privatized companies can be resold to state-owned companies.

In December 2001, Laurent Fabius, Minister for Finance and the Economy, stated his opposition to a proposed 5% increase in electricity rates by EdF in 2002. EdF raised rates 1% in November 2001.

Nuclear

France is the world's largest nuclear power generator on a per capita basis, and ranks second in total installed nuclear capacity (behind the United States). Because of France's extremely limited domestic energy sources, energy supply security and reliance on imports are major issues in France. Government policy has promoted a dramatic increase in nuclear power generation over the past three decades. Currently, about 75% of French electricity comes from France's 57 nuclear power plants. This represents a dramatic change from 1973, when fossil fuels accounted for more than 80% of French power generation. The government nuclear regulator is DSIN, and EdF operates the plants. In July 2001, France and the United States signed an accord to jointly fund U.S.-French research on advanced reactors and fuel cycle development.

France is now seen to be retreating slowly from its staunchly pro-nuclear position. Previously, the government planned to have nuclear power reach 100% of electricity generation. Environmental objections have increased in recent years. Germany's decision to phase out nuclear power started a public debate within France about the future of its own industry, and public opinion polls showed that a growing percentage of the public favors an end to nuclear power.

France now must decide whether to replace obsolete nuclear plants with more modern nuclear plants, or to begin phasing out nuclear power. Since 1997, the ruling government of Prime Minister Jospin has included members of the Green Party, *Les Verts*. The government has generally come to the conclusion that the volume of nuclear capacity exceeds its economically efficient contribution to the electricity market. Nevertheless, costs will fall when plants continue functioning past their 30-year capital amortisation periods, though how much longer they can function past thirty years is an open question.

In July 2001, the reorganization of the French nuclear sector commenced with the nomination of a management committee for a new holding company, Topco, that will preside over the country's major nuclear enterprises. Its nuclear operations will include mining, fuels, treatment, recycling, decontamination and engineering. As part of a restructuring program announced in Nov 2000, CEA-Industrie, Cogema and Framatome announced plans to merge Framatome with a company holding Cogema's stakes in Framatome, Eramet, TotalFinaElf and Cogerap. CEA-Industrie is the holding company for the state's Commissariat a l'Energie Atomique. The capital of the new company - Topco - eventually would be open to industrial partners and the amount of stock available on the market would be increased over time. The EC required this new structure in order to approve the merger of Framatome's nuclear business with that of Siemens of Germany that was approved in February 2001. EdF divested itself of Framatome, and EdF will now be able to have competitive bidding for nuclear services and supplies that formerly had been exclusively sourced from Framatome.

France is one the few countries in the world with a nuclear reprocessing plant. Cogema's La Hague facility received authorization from DSIN to start operations of two new facilities, hull and end-pieces compacting and plutonium purification and conditioning, in January 2002.

ENVIRONMENT

In terms of environmental issues, France is noted for using nuclear energy that results in less greenhouse gases, but this creates other environmental concerns. The country's lack of fossil fuel resources, in addition

to making France keenly aware of the importance of energy security, paradoxically has made France rely on cleaner energy sources. However, air pollution, especially in Paris, remains a pertinent environmental issue to urban dwellers.

In general, however, most energy-related environmental trends in France appear to be headed for greater efficiency and less environmental impact. The country's rate of energy consumption is holding steady, and France's energy and carbon intensity are on the decline. In addition, France has announced an extensive 10-year plan to curb its carbon emissions in order to meet its commitments under the Kyoto Protocol--one of the first countries to do so.

As part of this plan, France has reiterated its need to develop renewable energy sources to maintain its energy self-sufficiency. Although nuclear energy has helped to provide France with the energy independence the country desires, objections to nuclear energy are increasing. In the 21st century energy efficiency measures in all sectors of the economy likely will be needed in order to make further environmental improvement a realistic proposition.

Sources for this report include: CIA World Factbook; Dow Jones News Wire service; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Petroleum Economist; Petroleum Intelligence Weekly; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

President: Jacques Chirac (since May 1995)
Prime Minister: Lionel Jospin (since June 1997)
Independence: 486 (unified by Clovis)
Population (July 2001E): 59.6 million
Location/Size: Western Europe, bordering the Bay of Biscay and English Channel, between Belgium and Spain southeast of the UK; bordering the Mediterranean Sea, between Italy and Spain/547,030 sq km (slightly less than twice the size of Colorado)
Language: French 100%, rapidly declining regional dialects and languages (Provencal, Breton, Alsatian, Corsican, Catalan, Basque, Flemish)
Ethnic groups: Celtic and Latin with Teutonic, Slavic, North African, Indochinese, Basque minorities
Religions: Roman Catholic 90%, Protestant 2%, Jewish 1%, Muslim (North African workers) 3%, unaffiliated 4%
Defense (8/98): Army 203,200; Air Force 78,100; Navy 63,300

ECONOMIC OVERVIEW

Economy, Finance, and Industry Minister: Laurent Fabius
Currency: Euro (EUR)
Exchange Rate (1/10/02): 1 U.S. Dollar = EUR 1.12
Gross Domestic Product (GDP, 2001E): $1.21 trillion
Real GDP Growth Rate (2001E): 2.1% **(2002F):** 1.1%
Inflation Rate (consumer prices, 2001E): 1.7% **(2002F):** 1.3%
Unemployment Rate (2001E): 8.9% **(2002F):** 9.8%
Exports of Goods and Services (2001E): $294.3 billion
Imports of Goods and Services (2001E): $295.3 billion
Major Trading Partners: Germany, Italy, Belgium, the United Kingdom, the United States
Major Export Products: Machinery and transport equipment, agricultural products, chemical products
Major Import Products: Machinery and transport equipment, agricultural products, chemical products, and energy

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 140 million barrels
Oil Production (2001E): 78,000 barrels per day (bbl/d), of which 28,000 bbl/d is crude oil
Oil Consumption (2001E): 2 million bbl/d

Net Oil Imports (2001E): 1.9 million bbl/d
Crude Oil Refining Capacity (1/1/02E): 1.9 million bbl/d
Natural Gas Reserves (1/1/02E): 403 billion cubic feet (Bcf)
Natural Gas Production (1999E): 0.07 trillion cubic feet (Tcf)
Natural Gas Consumption (1999E): 1.35 Tcf
Net Natural Gas Imports (1999E): 1.28 Tcf
Coal Reserves (12/31/96E): 128 million short tons (Mmst)
Coal Production (1999E): 6 Mmst
Coal Consumption (1999E): 26 Mmst
Electric Generation Capacity (1/1/99E): 108 gigawatts
Electricity Generation (1999E): 497 billion kilowatthours (bkwh), 75% nuclear, 14% hydro, 10% thermal, less than 1% other renewables
Electricity Consumption (1999E): 399 bkwh
Net Electricity Exports (1999E): 98 bkwh

ENVIRONMENTAL OVERVIEW

Minister of Regional Development and Environment: Yves Cochet
Total Energy Consumption (1999E): 10.3 quadrillion Btu* (2.7% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 108.6 million metric tons of carbon (1.7% of world carbon emissions)
Per Capita Energy Consumption (1999E): 173.5 million Btu (vs. U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 1.8 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 7,324 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 0.08 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (40.0%), Residential (23.8%), Transportation (20.7%), Commercial (15.5%)
Sectoral Share of Carbon Emissions (1998E): Transportation (38.7%), Industrial (34.4%), Commercial (10.7%), Residential (16.2%)
Fuel Share of Energy Consumption (1999E): Oil (40.8%), Natural Gas (14.5%), Coal (5.9%)
Fuel Share of Carbon Emissions (1999E): Oil (66.4%), Natural Gas (19.7%), Coal (13.9%)
Renewable Energy Consumption (1998E): 1,161 trillion Btu* (2% increase from 1997)
Number of People per Motor Vehicle (1998): 1.9 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified March 25th, 1994). Signatory to the Kyoto Protocol (April 29th, 1998)- not yet ratified.
Major Environmental Issues: Some forest damage from acid rain; air pollution from industrial and vehicle emissions; water pollution from urban wastes and agricultural runoff.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Climate Change-Kyoto Protocol.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999.

Links

For more information from EIA on France, please see:
EIA - Country Information on France

Links to other U.S. Government sites:
CIA World Factbook - France
U.S. Department of Energy on French Nuclear Sector
U.S. State Department Consular Information Sheet - France
U.S. Department of Commerce Country Commercial Guide - France
U.S. State Department Background Notes on France
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January 2002

Spain

Spain is one of the fastest growing European economies but has very limited domestic energy resources. As a result, Spain is expected to become an increasingly important energy importer.

Note: The information contained in this report is the best available as of January 2002 and is subject to change.

BACKGROUND

Spain's period of rapid (4% annual growth) economic expansion is slowing. Still, Spain's forecast growth rate of 2.4% in 2002 is still well above the average "eurozone" growth rate forecast of 1.4%. The unemployment rate has decreased significantly (although projected at 12-13% for 2002), and government finances have improved over the past year. Inflation is expected to ease from 3.7% in 2001 to 2.4% in 2002 as unions have recently given priority to job creation over wage increases. Prime Minister Jose Maria Aznar's center-right Popular Party was re-elected with an absolute majority in March 2000. Aznar is continuing his liberalization of Spanish industry. Legislation aimed at getting rid of monopolies (state-held or private) in the energy, telecommunications, and services industries passed in June 2000. Oil, natural gas, and electricity markets are key targets in Aznar's liberalization program.

The recent economic and political turmoil experienced by Argentina has adversely affected Spanish companies, which invested EUR 45 billion there over the last decade. Five large Spanish companies, including oil company Repsol-YPF and power company ENDESA, that alone account for about three-

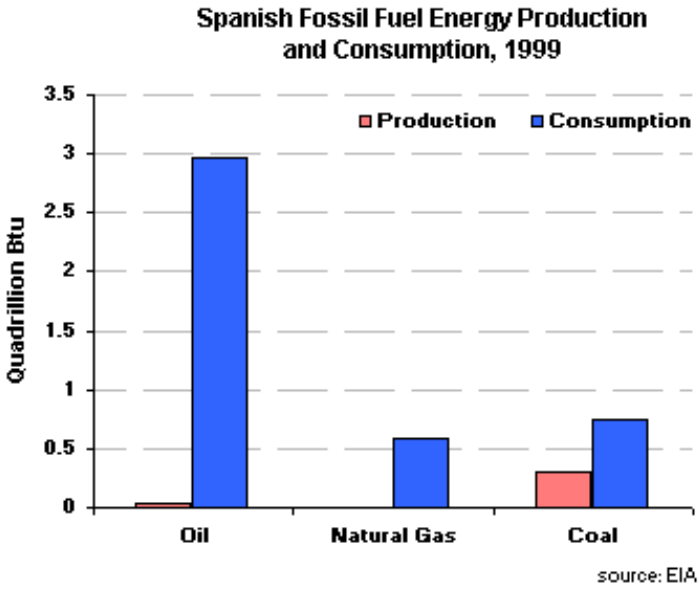
quarters of the trading volume on the Madrid stock exchange, are expected to lose billions of euros because of the default on Argentine government debt and the devaluation of the Argentine peso.

Spain's economic growth and accelerated industrialization associated with European Union (EU) membership have fueled energy demand, up 75% since the mid-1970s. Electricity demand is growing at a particularly rapid rate of 6% per year, reflecting a need for greater investment. Spain is highly dependent on imported oil, leaving the country economically vulnerable to world oil price fluctuations. Further energy demand increases are expected to be met largely with natural gas imports. The increasing use of natural gas has created a new dependency on Algeria, from which Spain obtains 60% of its natural gas imports. With an extensive gas network now in place, Spain's demand for natural gas is expected to increase dramatically during the next few years.

Spain assumed the six-month European Union (EU) presidency in January 2002, and Spanish Finance Minister Rodrigo Rato has announced that Spain will seek to establish a link between progress on the liberalization of energy markets and energy tax harmonization during its term. In December 2001, government energy regulator CNE recommended a EUR 4 billion investment in Spain's natural gas and electricity sectors in order to guarantee supply, to be financed mostly by Red Electrica and Gas Natural's Enagas.

OIL

Oil plays a major (albeit decreasing) role in the Spanish energy sector. In the 1970s, oil accounted for 73% of Spain's primary energy consumption. That percentage has now fallen to less than 60% and is expected to fall further as natural gas becomes an increasingly important fuel source. In 2001, Spain consumed about 1.5 million barrels per day (bbl/d) of oil, 99% of which was imported.



Spain has very limited domestic oil reserves and production. The largest producing area is in the Mediterranean Sea, with the Casablanca complex producing about 4,000 bbl/d. In October 2001, Spain authorized Conoco's UK subsidiary to explore for hydrocarbons off the coast of the southern Mediterranean province of Malaga. The permit for exclusive exploration rights is for six years.

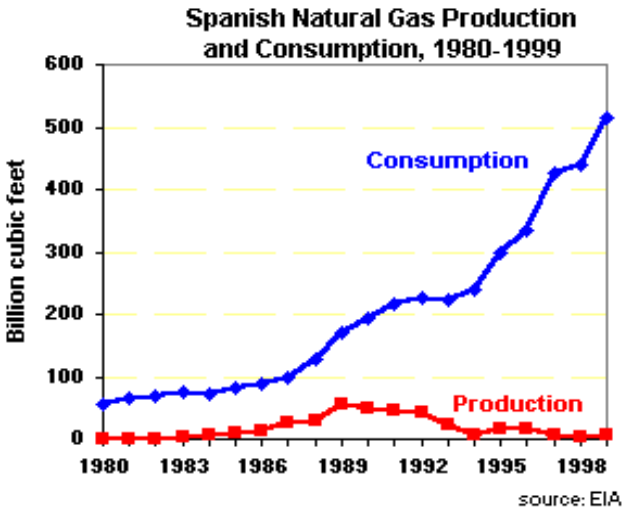
Until 1993, the Spanish oil industry was state-controlled. Today, formerly state-held (now private) Repsol still dominates the Spanish oil sector (and also the Spanish natural gas sector, through a controlling share in the Gas Natural Group). The company acquired the top Argentine oil company, YPF, in 1999, changing the company name to Repsol-YPF. Repsol-YPF is responsible for over 50% of Spain's oil production. Worldwide, the company has reserves of 4.8 billion barrels of oil equivalent and and a daily production of about 1 million barrels of oil equivalent per day. The company owns the majority of Spain's refineries, its distribution network (through Compania Logistica de Hidrocarburos, CLH, in which it holds a majority stake), and its gasoline stations (through its trademarks Repsol, Campsa, and Petronor). Divestments in the wake of the merger are working to lessen Repsol-YPF's control in the industry. June 2000 economic liberalization plans also work toward this end; the company's share in CLH must be reduced from 62% to 25%. Repsol-YPF's profits will be much lower for 2001 than the record $2.10-billion profit achieved in 2000 because of the Argentine economic situation. Repsol-YPF derives 45% of its operating income from Argentina's oil and natural gas fields, and is negotiating a "contribution" to Argentina's government expected to be between $300 million and $500 million.

Compania Espanola de Petroleos (Cepsa), established in 1929, is Spain's oldest private oil and gas company. The company has exploration and production activities in Colombia and Algeria. It is the second largest oil group in Spain, with a 25% retail market share. BP Oil is also active in Spain. Repsol, Cepsa, and BP Oil account for almost all of the activity in the Spanish oil sector.

Refining

Spain has nine major refineries. Four are owned by Repsol, and another is owned by a Repsol subsidiary, Petronor, in which Repsol has an 88% stake. Cepsa owns three, and one is owned by BP. Because of state regulation of the industry, Spain has avoided developing the excess refining capacity that characterizes some other countries in southern Europe. Spain's total crude oil refining capacity stands at 1.3 million bbl/d.

NATURAL GAS



Natural gas is expected to account for a much larger share of Spain's total energy consumption in coming years, especially as new pipelines and natural gas-fired power plants come on line. Natural gas consumption has grown from 2% of total energy consumption in the 1970s to more than 11% in 1999. Preliminary estimates of consumption for 2000 are about 611 billion cubic feet (Bcf). Some estimates predict natural gas consumption growing at a 15% annual rate in this decade. Spanish energy company Endesa predicts demand for natural gas rising to about 883 Bcf by 2005. Almost all of this consumption will be satisfied with imports, as Spain has extremely limited natural gas reserves. The country's largest natural gas field went out of production in 1995, and only a very small number of smaller fields remain in production.

The Gas Natural Group (GN) is the leading natural gas conglomerate in Spain, dominating Spain's gas sector with 90%-95% of the market. However, in the market for industrial customers, which was partially opened in 2000, GN's market share was down to 79% by the first half of 2001. Repsol-YPF controls the Group, with 47% of its shares and majority board representation. GN is comprised of Gas Natural SDG, the main natural gas distributor in Spain; Enagás, a transport company; Gas Natural Aprovisionamientos (supplies); Gas Natural Comercializadora (commercialization); Gas Natural Servicios, the services company of the Group; Gas Natural Overseas Trading Company; 14 natural gas distribution companies in Spain; and Gas Natural Internacional, which brings together in a single business unit the interests of GN in Gas Natural BAN (Argentina), Gas Natural ESP (Colombia), Companhia Distribuidora de Gas do Rio de Janeiro-CEG, CEG RIO and Gas Natural SPS (Brazil), in addition to Gas Natural México. Also, GN has minority holdings in three natural gas distribution companies in the region of Aragon and in the Basque Country.

According to liberalization legislation passed in June 2000, no single operator may command over 70% of the Spanish natural gas market by 2004. Since June 2000, large industrial consumers have been able to choose suppliers, and all consumers should be able to choose suppliers by 2003. Several additional regulatory measures were taken in 2001: In July, Spain's Economy Ministry published the terms under which GN must auction off one-third of its 580 Bcf per year Algerian pipeline natural gas imports. In September, Spain's Economy Ministry detailed new natural gas sector regulations that include a revised system for calculating pipeline tariffs and procedures for accessing the national grid. Finally, in October, the government ended GN's monopoly of natural gas imports when a contract for Algerian gas imports equivalent to about 25% of Spain's total annual consumption was awarded to Spain's four largest electricity companies (Endesa, Iberdrola, Union Fenosa, and Hidrocantabrico), BP, and Royal Dutch/Shell. This is part of a strategy being pursued by Spanish electricity companies to enter into the natural gas market. As Algeria supplies about 75% of Spain's imports, these companies now control about 19% of the market. These

companies have until 2004 to sell the natural gas to their industrial clients. The planned sale of 65% of GN subsidiary Enagas cannot be valued until the publication of new natural gas tariffs by the government, expected sometime in 2002.

The Group's Enagás transports natural gas imports to the Iberian Peninsula via gas pipelines connected to international networks (or via methane carriers for liquefied natural gas, discussed below). There are two international gas pipelines in Spain: Lacq-Calahorra in the north and the Pedro Duran Farell pipeline (formerly the Mahgreb-Europe line) in the south. The Lacq-Calahorra gas pipeline is the main Spanish connection to the European network, linking to Norway's North Sea gas sources. The Pedro Duran Farell pipeline, which crosses through Algeria and Morocco and travels under the Strait of Gibraltar, is about 870 miles (1,400 kilometers) long and connects the Algerian deposits with the Spanish gas pipeline network in Córdoba. This pipeline made its first Spanish delivery in 1996. Work is underway to expand the Pedro Duran Farell pipeline's annual capacity from 282.5 Bcf to 388.5 Bcf by adding a compressor station. Completion is expected in late 2003.

There are two new projects underway as well. Spain will have an additional connection with France via Irun in the Basque Country as a new transfrontier connector is being built with completion expected by the end of 2003. A further extension of the pipeline network coming to and from Irun is planned to be ready between 2005 and 2008. It will have 111 miles in Spain and 93 miles in France, and possess an annual capacity of 144.8 Bcf. In July 2001, Cepsa and Sonantrach of Algeria signed an agreement for the construction of the new Medgaz undersea natural gas pipeline between Algeria and Almeria, Spain, which received political backing in August. A feasibility study is scheduled to be completed in early 2003. The pipeline would have a length of 137 miles and have a capacity of between 282.5 Bcf and 353 Bcf. Natural gas would be alloted in proportion to each shareholder's equity ownership. At present, Sonatrach and Cepsa each hold 20%, while BP, Endesa, Eni, Gaz de France, and TotalFinaElf each hold 12%. Some natural gas from this pipeline may transit through Spain onto other European destinations.

Liquefied Natural Gas

Spain is Europe's second-largest liquefied natural gas (LNG) importer, behind France. Spain has three regasification terminals (Barcelona, Cartagena, and Huelva), the most of any country in Europe. All three are owned and operated by GN. Algeria is Spain's largest LNG supplier. Spain also is involved in long-haul LNG transit, importing LNG from the United Arab Emirates and Qatar. In 1999, Spain began receiving shipments from Trinidad and Tobago and Nigeria. In October 2000, shipments began from Oman, with 17 received through the end of January 2002. In June 2001, GN and Enel of Italy signed an agreement to develop joint marketing and sales negotiations for LNG internationally.

The GN plans to expand its three regasification terminals and its tanker fleet in order to handle increased LNG imports for rising domestic consumption. Spanish electricity generator Union Fenosa signed a firm contract with the Egyptian General Petroleum Corporation in July 2000 for the purchase of LNG from a new liquefaction terminal under construction at Damietta, Egypt. Union Fenosa and Iberdrola, which are constructing the new receiving gasification plant together, had disagreed on the location, but in November 2001 they settled on Fenosa's proposal at the Sagunto port in Valencia. The plant, to be completed in winter 2004, will be able to process 282.5 Bcf per year and will be linked to new combined cycle gas turbine plants being constructed by Fenosa nearby and Iberdrola in Castellon. Some of the natural gas will also transit to other locations.

A new regasification plant is planned for northern Spain. The Bahia de Bizkaia Gas group, a consortium led by BP and including Repsol-YPF, Iberdrola, and EVE (the Basque Energy Authority), will build the new import facility in conjunction with a new power station. The regasification facility is expected to begin operations in 2003.

Seven Spanish companies and Algeria's Sonatrach, forming the Reganosa group, will begin building in 2002 another new LNG import facility. Algerian LNG will supply the new Ferrol terminal in Galicia in northwest Spain for ten years following the terminal's projected 2004 commissioning. In conjunction with the terminal, which will have an initial capacity of 88 Bcf per year, a new pipeline will be constructed to

connect the terminal to power plants located about 60 miles away.

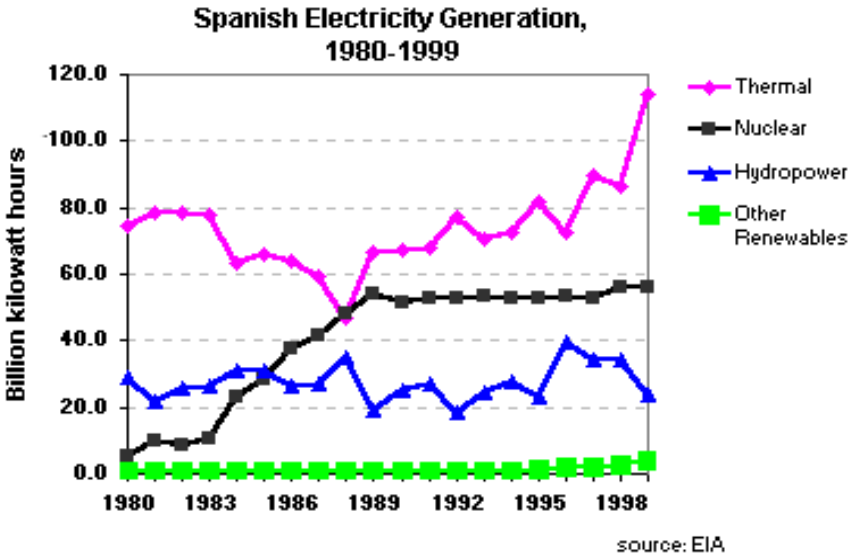
COAL

Coal is Spain's most plentiful indigenous energy source. Production has fallen in recent years, and the decline is expected to continue as Spain works to meet environmental standards. Currently, 95% of coal is used to generate electricity. All of the major coal companies are state-owned.

Spanish coal is too expensive to be competitive in a free energy market, with about 80% of the coal costing at least twice international prices to produce, so the Spanish government subsidizes coal production. According to new EU regulations that will take effect in July 2002, Spain must lower its coal production by 65% over the next ten years. Also, coal mines that do not improve their economic viability will only be able to receive production subsidies until 2008. Spain is one of three EU countries that will be permitted to continue coal production for reasons of economic security, and hence will continue to receive subsidies for more competitive mines. There is increased pressure on coal, however, as the electricity market privatizes, and as electricity generation will no longer be a captive market for domestic coal. Imports of foreign coal already are on the rise, and electricity generators are looking more to natural gas.

The sector now employs only half the number of people as a decade ago. However, most of those employed are in the Asturias region, where the jobs are badly needed. It would be difficult to completely phase out coal mining because of this region's dependence on the industry for employment.

ELECTRICITY



Spain has the fifth largest electricity market in Europe (behind Germany, France, the United Kingdom, and Italy), and it is growing quickly. Electricity demand is estimated to have grown by 5.4% in 2001 to about 205 billion kilowatthours (bkwh). Red Electrica de España (REE), Spain's network operator, invested heavily in the network in 2001, with EUR 78.4 million invested in expanding the electricity network and REE announced plans in October 2001 to invest between EUR 60.2 million and EUR 72.2 million to improve the electricity connection with France. Spain's three largest electricity groups - Endesa, Iberdrola, and Union Fenosa - have announced massive investments planned from August 2001 to 2005 of EUR 34 billion, with much of that in Latin America and other European countries, but nevertheless including EUR 8 billion for new generating plants in Spain.

Endesa announced in July 2001, that it will build a natural-gas-fired, 400-megawatt (MW), combined-cycle generating turbine (CCGT) plant in Huelva by June 2004, in addition to three other gas-fired 400-MW CCGTs the company already has under construction in Spain near Cadiz, Barcelona, and Tarragona. Union Fenosa plans to add 5,000 MW of new capacity by 2005, mostly in Spain, of which 2,800 MW would be natural-gas-fired. Piemsa, an affiliate of Petronor, is planning to construct an 800-MW integrated gasification combined-cycle (IGCC) complex at a refinery near Bilbao that will make use of heavy refinery stocks. The plant will be one of the largest and most advanced of its kind in the world.

Spain's electricity market is privatizing ahead of the schedule mandated by the EU. A 1996 EU directive required that at least 26.48% of electricity sales in member countries be open to competition, beginning in February 1999. This requirement increased to about 28% in February 2000 and will grow to 33% in 2003.

Spain already has surpassed the 2003 requirement.

The Spanish electricity sector is in the midst of restructuring. There are five major utility companies in Spain, in descending order of size: the formerly state-held Endesa, Iberdrola, Union Fenosa, Hidrocantabrico, and the newly independent Viesgo. Viesgo's acquisition by Enel of Italy from Endesa was completed in January 2002, and Viesgo has a 5% market share. This is part of Enel's strategy of regaining market share abroad after selling its Elettrogen utility at home to Endesa in 2001.

Hidrocantabrico was sold in October 2001 to Electricite de France (EdF) and Eletricidade de Portugal (EdP), after the Spanish government decided to lift the veto on EdF's and EdP's voting rights. Some 60% of Hidrocantabrico will actually be owned by Energie Baden-Wurttemberg (EnBW) of Germany, which is controlled by EdF. The agreement is subject to commitments by the French and Portuguese governments to open up their electricity markets to Spain and subject to France increasing its interconnection with Spain from 1,000 MW to 4,000 MW between 2006 and 2011. This includes a new 1,200 MW line to run along side the planned high-speed rail line between Perpignan and Figueras in Catalonia.

In August 2001, Spain and Portugal signed an agreement to form a single electricity market by completely unifying their electricity networks. The unification is to be completed by sometime in 2003. There are still several unresolved obstacles to this. One obstacle is that there is minimal separation between transport and distribution activities, which remain monopolies, and production and marketing activities, which are open to competition. Another problem is that in Portugal production is sold to the state-held REN, which transports the electricity, whereas in Spain producers compete to sell electricity, but receive compensation payments for market liberalization called CTCs. The Spanish government in March 2001 reiterated its support for CTCs, but these payments are under investigation by the EU. The opposition PSOE party has called for their end. However, electricity companies have called for an end to tariff privileges enjoyed by several large industrial companies that they believe have made these companies uncompetitive internationally. In addition, electricity companies would like to raise their rates, arguing that prices have fallen 17% in the past five years, while inflation for the period has been 14%. In December 2001, a 1% rate increase was authorized for industrial customers. The Economy Ministry began investigating several electricity companies for alleged restrictive practices in order to raise prices in November 2001, though it has not revealed which companies are under investigation.

As electricity demand has increased rapidly in Spain in the past year combined with flat or low hydroelectric capacity, domestic supply has not been sufficient, and Spain began to import electricity from Morocco for the first time in December 2001 when cold temperatures created a surge in demand. Union Fenosa and Endesa have signed agreements with Moroccan power company ONE. Spain granted ONE the status of an "external operator" in 1998, giving the company the right to deal directly with Spanish electricity companies or on the Spanish spot market. The power exchange between ONE and Spanish companies is through the Spain-Morocco grid interconnection, which became operational in 1998. Two power connections between Algeria and Spain are also planned, one of which will run along side the Medgaz pipeline.

Spanish utilities are becoming increasingly involved in foreign power markets, especially in Latin America. Endesa owns a controlling stake in Chile's largest power provider, Union Fenosa is involved in Guatemala and Panama, and Hidrocantabrico has interests in Mexico. In neighboring France, Endesa acquired a 30% stake in SNET, which owns five coal-fired power plants, and hopes to control the company completely in a few years.

Nuclear Power

Spain is about 27% reliant on nuclear power for its electricity generation. Spain currently has nine nuclear reactors. In 2001 Spain's nuclear plants produced a record 63.6 bkwh, an increase of 2.3% compared to 2000. The Popular Party supports nuclear power, but the PSOE has indicated that it supports a gradual shut-down of Spain's nuclear plants. Currently, the construction of new nuclear plants is not illegal, but companies are unlikely to invest in such plants because of high costs and little government incentive.

COUNTRY OVERVIEW

Head of State: King Juan Carlos (since November 1975)
Prime Minister: Jose Maria **Aznar** (since May 1996)
Independence: 1492 (expulsion of the Moors and unification)
Capital City: Madrid
Population (July 2001E): 40 million
Location/Size: Southwestern Europe, bordering the Bay of Biscay, Mediterranean Sea, North Atlantic Ocean, and Pyrenees Mountains, southwest of France/504,750 sq km (slightly more than twice the size of Oregon)
Language: Castilian Spanish 74%, Catalan 17%, Galician 7%, Basque 2%
Religion: Roman Catholic 99%, other 1%

ECONOMIC OVERVIEW

Finance Minister: Cristobal Montoro
Currency: Euro (EUR)
Exchange Rate (1/29/2002): 1 US Dollar = 1.156 EUR Spanish Peseta
Gross Domestic Product (GDP, nominal, 2001E): $579 billion
Real GDP Growth Rate (2001E): 2.6% **(2002F):** 2.4%
Inflation Rate (consumer prices, 2001E): 3.7% **(2002F):** 2.4%
Unemployment Rate (2001E): 13.4% **(2002F):** 13.0%
Merchandise Exports (2000E): $115.1 billion
Merchandise Imports (2000E): $147.8 billion
Merchandise Trade Deficit (2000E): $32.7 billion
Major Trade Partners: France, Germany, Italy, United Kingdom, United States, Portugal
Major Export Products: Automobiles, tourism, power generation equipment, electrical machinery, petroleum and chemical products, foodstuffs
Major Import Products: Crude petroleum, vehicle and automobile parts, capital goods, and food

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 21 million barrels
Oil Production (2001E): 21,000 barrels per day (bbl/d), of which 7,000 bbl/d was crude oil
Oil Consumption (2001E): 1.48 million bbl/d
Net Oil Imports (2001E): 1.46 million bbl/d
Crude Oil Refining Capacity (1/1/02E): 1.3 million bbl/d
Natural Gas Reserves (1/1/02E): 18 billion cubic feet (Bcf)
Natural Gas Production (1999E): 5.1 Bcf
Natural Gas Consumption (1999E): 513.8 Bcf
Net Natural Gas Imports (1999E): 508.7 Bcf
Coal Reserves (12/31/96): 728 million short tons (Mmst)
Coal Production (1999E): 27 Mmst
Coal Consumption (1999E): 49 Mmst
Electric Generation Capacity (1999E): 44.9 million kilowatts
Electricity Generation (1999E): 197.7 billion kilowatthours (bkwh)
Electricity Consumption (1999E): 189.6 bkwh

ENVIRONMENTAL OVERVIEW

Minister of Environment: Jaume Matas
Total Energy Consumption (1999E): 5.2 quadrillion Btu* (1.4% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 81.5 million metric tons of carbon (1.3% of world carbon emissions)
Per Capita Energy Consumption (1999E): 132.6 million Btu (vs U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 2.1 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 8,707 Btu/$1990 (vs U.S. value of 12,638 Btu/$1990)**

Carbon Intensity (1999E): 0.14 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (43.1%), Transportation (31.6%), Residential (15.0%), Commercial (10.3%)
Sectoral Share of Carbon Emissions (1998E): Industrial (39.3%), Transportation (38.9%), Residential (13.1%), Commercial (8.7%)
Fuel Share of Energy Consumption (1999E): Oil (57.0%), Coal (14.3%), Natural Gas (11.2%)
Fuel Share of Carbon Emissions (1999E): Oil (66.6%), Coal (23.1%), Natural Gas (10.3%)
Renewable Energy Consumption (1998E): 521.4 trillion Btu* (1% increase from 1997)
Number of People per Motor Vehicle (1998): 2.1 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 21st, 1993). Signatory to the Kyoto Protocol (signed April 29th, 1998 - not yet ratified).
Major Environmental Issues: Pollution of the Mediterranean Sea from raw sewage and effluents from the offshore production of oil and gas; water quality and quantity nationwide; air pollution; deforestation and desertification.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Desertification.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999.

Sources for this report include: CIA World Factbook; DRI/WEFA; Economist; Economist Intelligence Unit; European Union; Financial Times; Gas Natural; Petroleum Economist; Repsol; U.S. Energy Information Administration; World Markets Online.

Links

For more information from EIA on Spain, please see:
Spain Country Data

Links to other U.S. Government Sites:
CIA World Factbook - Spain
U.S. State Department Consular Information Sheet - Spain
U.S. State Department Country Commercial Guide - Spain
U.S. State Department Background Notes - Spain
U.S. Embassy in Spain

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June 2002

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Azerbaijan

Since becoming independent in 1991, Azerbaijan has attracted significant international interest in its substantial oil and natural gas reserves. Foreign investors are helping the country to develop its rich oil and natural gas reserves in the Caspian Sea basin, and construction of new pipelines may allow Azerbaijan to become a significant energy exporter in the next decade.

Note: Information contained in this report is the best available as of June 2002 and is subject to change.

GENERAL BACKGROUND

Azerbaijan received its independence from the Soviet Union in 1991, but the country continues to face considerable problems in making the transition from a command to a market economy, including the loss of its traditional markets, the need to diversify its economy, excessive bureaucratic regulation, and the slow pace of structural reform. Fighting broke out between Azerbaijan and Armenia in 1988 over Nagorno-Karabakh, an Azerbaijani enclave that is largely Armenian populated. A ceasefire was declared in 1994, one year after Azerbaijani President Heydar Aliyev took power in a bloodless coup, but Azerbaijan lost almost 20% of its territory and has been forced to support some 750,000 displaced Azeris.

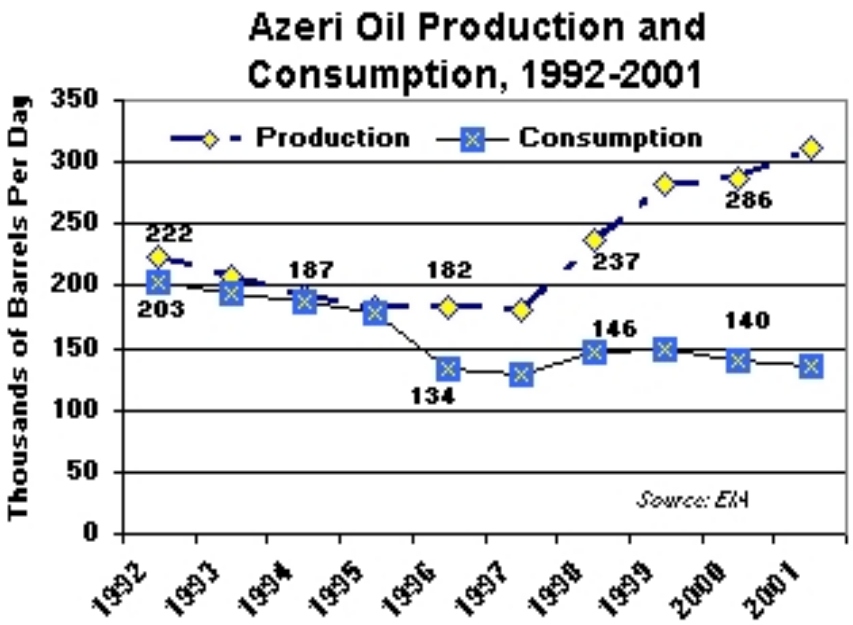
As a result of the conflict, Azerbaijan implemented an economic blockade of both Nagorno-Karabakh and Armenia, which is still in effect. In 1992, the United States passed Section 907 of the Freedom Support Act, restricting U.S. government assistance to Azerbaijan until Azerbaijan takes "demonstrable steps to cease all blockades and other offensive uses of force against Armenia and Nagorno-Karabakh." In January 2002, U.S. President George W. Bush granted Azerbaijan a waiver on Section 907 due to the country's support for the U.S.-led war on terrorism.

Azerbaijan's real gross domestic product (GDP) contracted by almost 60% from 1990 to 1995, but the country began a period of steady growth in the

latter half of the decade, fueled by foreign investment in the country's bountiful oil and natural gas sectors. The oil industry currently accounts for 70% to 80% of total foreign investment in Azerbaijan, and foreign direct investment increased from $15 million in 1993 to $827 million in 1999, about 20% of Azerbaijan's GDP. Azerbaijan's posted its fifth straight year of economic growth in 2001, with a real GDP increase of 5.2%. Azerbaijan's real GDP is forecast to increase another 5.7% in 2002, but even with this steady growth and continued foreign investment, Azerbaijan's GDP is not expected to reach its 1991 level until 2007.

Azerbaijan's hope for future economic growth rests with successful development of its vast oil and natural gas resources in the Caspian Sea region. Crude oil and oil product exports make up over 70% of Azerbaijan's exports, and oil-related revenue makes up nearly 50% of budget revenues. On December 29, 1999, President Aliyev issued a decree creating a State Oil Fund designed to use money obtained from oil-related foreign investment on education, reducing poverty, and raising the living standards of the rural population in Azerbaijan. In 2002, the State Oil Fund is expecting to take in $185 million. However, the unresolved Nagorno-Karabakh conflict remains an obstacle to economic progress, and the country still faces several years of tight finances, as Azerbaijan's oil revenues are likely to remain limited until 2005.

OIL



Azerbaijan is one of the world's oldest oil-producing countries. The country's oil industry experienced a boom at the beginning of the 20th century, and during World War II, the Azerbaijani Soviet Republic produced approximately 500,000 barrels per day (bbl/d). However, oil production in Azerbaijan dropped off dramatically in the post-war years as the Soviet Union directed resources for energy development elsewhere. In addition, due to extensive oil development combined with a lack of environmental protection measures, Azerbaijan's coastline and the Caspian Sea suffered heavy environmental damage during the Soviet era.

Following Azerbaijan's independence in 1991, the country's oil production continued to decline, falling to just 180,000 bbl/d in 1997. Yet, with Azerbaijan's 1.2 billion barrels of proven oil reserves, as well as enormous possible reserves in undeveloped offshore Caspian fields, international investors and multinational energy companies began flocking to independent Azerbaijan in the early 1990's, looking to tap the country's huge hydrocarbon wealth. Since 1996, over $4 billion has been invested in the country's oil sector, and Natik Aliyev, president of the State Oil Company of the Azerbaijani Republic (SOCAR), has stated that he expects investment in the country's oil sector to surpass $60 billion.

As a result of the large amount of foreign investment in Azerbaijan's oil sector, the decline in the country's oil production has been halted, and in 1998 the trend was reversed. In 2001, Azerbaijan posted its fourth consecutive annual increase in its average oil production, as output rose to 311,200 bbl/d. Preliminary EIA data shows that Azerbaijan's oil production has remained

stable in 2002, averaging 310,200 bbl/d through March.

Over 80% of Azerbaijan's oil production currently comes from offshore, with a significant percentage coming from the shallow-water section of the Gunashli field, located 60 miles off the Azeri coast. Development of new fields through joint ventures (JVs) and production sharing agreements (PSAs) in the Caspian Sea likely will boost Azerbaijan's oil production well beyond its earlier peak, with predictions that Azerbaijani oil exports could exceed 1 million bbl/d by 2010 and 2 million bbl/d within 20 years.

To date, Azerbaijan has signed 21 major field agreements with 33 companies from 15 countries. However, not all of these projects have been successful, with several projects announcing disappointing drilling results and several JVs and PSAs shutting down, including the Caspian International Petroleum Company and the North Absheron Operating Company. In addition, restrictions on the ability of JVs to export their oil directly has contributed to a lack of development at some fields. To spur increased development, Azerbaijan decided to abolish JVs and convert them to PSAs in 2000.

Oil production from the country's first PSA, with the Azerbaijan International Operating Company (AIOC), began in November 1997. In September 1994, in what was described as "the deal of the century," AIOC, an international consortium made up of 10 energy companies, signed an $8 billion, 30-year contract to develop three fields (Azeri, Chirag, and the deepwater portions of Gunashli, ACG) with total reserves estimated at 4.3 billion barrels of oil. Almost all of Azerbaijan's oil production increases since 1997 have come from AIOC, which is operated by BP (U.K.). From November 1997 through the end of 2001, AIOC had produced a total of 133.5 million barrels of oil, mostly from the Chirag-1 stationary platform. In the first four months of 2002, AIOC produced 1.98 million tons of oil (an average of 120,000 bbl/d) from ACG deposits, with plans to increase output to 130,000 bbl/d by the end of 2002.

Azerbaijan's big production surge in the next decade is expected to come from further development of ACG. In August 2001, AIOC and Azeri government officials signed an agreement to carry out an expansion at ACG. The cost of the expansion plans, called Phase One, is estimated at $3.3 billion. Phase One envisages the construction of a drilling platform for 48 wells, a natural gas compressing facility, an underwater pipeline from the Azeri field, and modernization of an onshore oil terminal. AIOC production is slated to increase to 400,000 bbl/d by 2004 with the full implementation of Phase One plans.

Caspian Issues

Continued uncertainty over the Caspian Sea's legal status is hindering further oil and natural gas development in the area. The Caspian Sea littoral states--Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan--thus far have failed to agree on a plan to divide up the sea's resources, including the oil-rich seabed. Azerbaijan, along with Russia, and Kazakhstan, has advocated the establishment of maritime boundaries based on an equidistant division of the sea, but Iran and Turkmenistan disagree.

Azerbaijan remains locked in disputes with Turkmenistan and Iran over competing claims to overlapping fields. Turkmenistan and Azerbaijan have traded harsh words over the Kyapaz-Serdar, Khazar, and Osman fields, while Azerbaijan has objected to Iran's decision to award Royal Dutch/Shell and Lasmo a license to conduct seismic surveys in a region that Azerbaijan considers to fall in its territory. In July 2001, tensions flared in the South Caspian when a British Petroleum (BP) ship, licensed to explore Azerbaijan's Araz, Alov, and Sharg concession, was ordered to leave the area by an Iranian gunboat, since Iran considers the area, which it calls Alborz, to be a part of the Iranian sector of the sea. Although a long-delayed summit of the heads of state of the Caspian littoral states was held in Ashgabat in April 2002, the meeting, as expected, failed to produce a final resolution of the sea's status.

Oil Exports

Currently, Azerbaijan's only export routes are the Baku-Novorossiisk pipeline ("northern route"), which sends Azeri oil to the Russian Black Sea, and the Baku-Supsa pipeline ("western route"), which mainly carries AIOC's "early oil" from ACG to Georgia's Black Sea coast. Oil products such as lubricants also are exported by rail in tank wagons to Georgia's Black Sea ports.

In September 2000, Azerbaijan decided to attempt to boost its oil exports by switching its power-generating facilities from a fuel-oil regime to one that uses natural gas. However, problems with natural gas supplies during the winter of 2000-2001 reduced Azerbaijan's oil export potential, since fuel oil was needed domestically. As a result, the Azeri government temporarily ordered SOCAR to suspend exports. SOCAR resumed exports via Novorossiisk in December 2000, but overall, Azerbaijan had net oil exports of just 146,000 bbl/d in 2000. In 2001, preliminary data shows that Azeri net oil exports rose to 175,200 bbl/d.

Azerbaijan's options for increasing its oil exports depend to a large extent on the construction of new pipelines. Several oil export pipelines from the Caspian Sea region have been under consideration, but Azerbaijan has not wavered in its support for the proposed Baku-Ceyhan pipeline. This so-called "Main Export Pipeline" would export Azeri (and possibly Kazakh) oil along a 1,040-mile route from Baku via Georgia to the Turkish Mediterranean port of Ceyhan, allowing oil to bypass the increasingly crowded Bosporus Straits. Construction of the 1-million-bbl/d-pipeline, which is estimated to cost $2.9 billion, is scheduled to begin in the summer of 2002. In addition, Iran, Russia, and Ukraine also have proposed alternative oil export routes for Azerbaijan.

Downstream/Refining

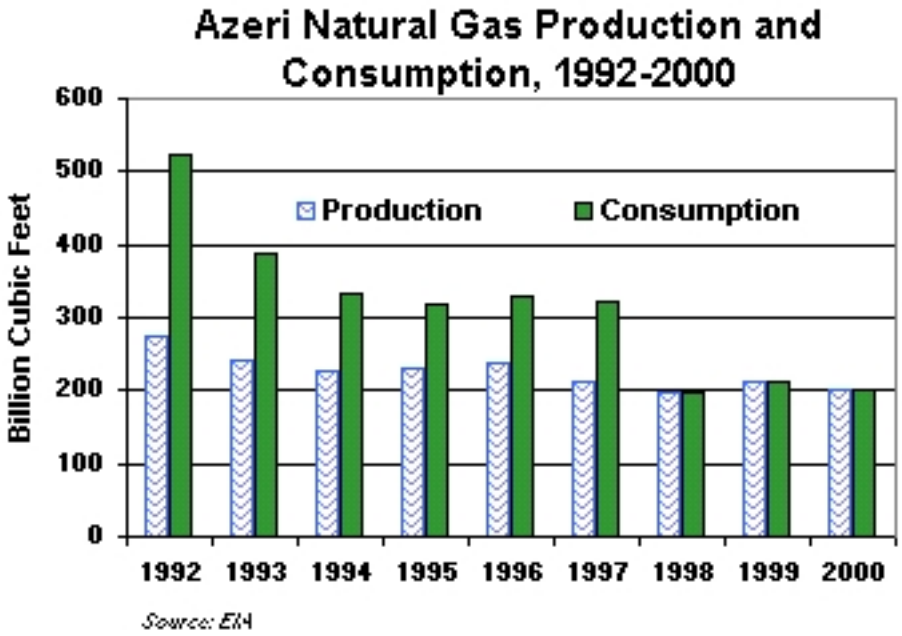
Azeri crude oil is refined domestically at two refineries: the Azerineftyag (Baku) refinery, with a capacity of 230,000 bbl/d, and the Azerneftyanajag (New Baku) refinery, which has a capacity of 212,000 bbl/d. With domestic production topping out at 311,200 bbl/d in 2001 (and half of that exported as crude oil), Azerbaijan's refineries have been running well below capacity,

with overall refinery utilization rates as low as 40%. Heating oil accounts for approximately 50% of output at Azeri refineries, followed by diesel fuel (28%), gasoline (10%), motor oil (7%), kerosene (3%), and other products (2%).

Both of the country's refineries are in need of modernization, which the Azeri government estimates will cost between $600 million and $700 million. The U.S. Trade and Development Agency is financing a $600,000 feasibility study for upgrading the two refineries and the specialized oil port of Dubendi. In January 2002, ABB Lummus was named the winner of the tender to prepare the feasibility study. Modernization of the two refineries will enable Azerbaijan to process imported crude oil, thereby freeing up domestic oil for export via the Baku-Ceyhan pipeline.

NATURAL GAS

With so much international attention focused on Azerbaijan's oil potential, the country's natural gas sector has often been overlooked. Azerbaijan has proven natural gas reserves of roughly 4.4 trillion cubic feet (Tcf), with significant potential reserves, but because there is no developed infrastructure to deliver natural gas from offshore fields (the source of the majority of the country's production), natural gas has been flared off instead of being piped to markets.



In 1999, however, Azerbaijan enacted a law requiring that each oil and natural gas production project include a plan to develop its natural gas potential. In addition, in October 1999, the U.S. Trade and Development Agency signed a

$425 million agreement with SOCAR to help fund a comprehensive study on Azerbaijan's natural gas sector to assess its consumption needs and its production and export potential. According to EIA figures for 2000, Azerbaijan's natural gas production slipped by 5.6% to 200 Bcf.

Currently, the Bakhar natural gas field is the country's most important source of natural gas production, accounting for over 40% of total production in 2000. SOCAR produces approximately 85% of Azerbaijan's natural gas, and AIOC produces a small amount of associated gas as well. Azerbaijan's offshore natural gas production is more than 21 times that of its onshore production, but with output declining at Bakhar (due to a lack of new drilling), the country's future natural gas potential hinges on development of the Nakhchivan, Gunashli, and Shah Deniz fields.

Nakhchivan is estimated to contain 900 Bcf in reserves, while Gunashli could be brought online shortly. The Shah Deniz field, which is thought to be the world's largest natural gas discovery since 1978, is estimated to contain between 25 Tcf and 39 Tcf of natural gas. Development of the field, which will cost upwards of $4.5 billion including related infrastructure, should produce the first natural gas by 2004. Azerbaijan is planning to extract 286 Bcf of natural gas per year from Shah Deniz during the first stage of development, allowing Azerbaijan to become self-sufficient in natural gas.

In the meantime, however, Azerbaijan is forced to import natural gas to meet domestic demand. Although the country's natural gas consumption has been on the decline since 1991, Azerbaijan still must import natural gas, since it exports some of its own natural gas to Georgia and to northern Iran. In addition, in an effort to free up around 40,000 bbl/d more crude oil for export, in 2000 Azerbaijan made the decision to switch its power-generating facilities from a fuel oil regime to one that uses natural gas. In 2001, Azerbaijan imported 125 Bcf of natural gas from Russia, including 109 Bcf from Russian natural gas trader Itera, with the remainder from TransNafta.

Azerbaijan plans to increase natural gas imports from Russia by 13% in 2002,

to 141 Bcf. Itera has an exclusive contract with SOCAR to supply the Azeri natural gas market in 2002, with supplies piped via the Shirvanovka-Gadzhigabul pipeline at $52 per 1,000 cubic meters (35,300 cubic feet). Through the first four months of 2002, Itera had supplied Azerbaijan with just over 58 Bcf of natural gas. Azerigaz, the state natural gas distribution company, completed maintenance on the Shirvanovka-Qazax pipeline in April 2002, allowing Azerbaijan to increase the volume of natural gas imports from Russia, via Georgia, to 177-212 Bcf if necessary.

Azerbaijan and Iran have been in discussions about exporting up to 70.5 Bcf of Iranian natural gas to Azerbaijan through Astara, as well as piping Iranian liquefied natural gas (LNG) to the Nakhchivan exclave through Culfa. However, the Gadzhigabul-Astara pipeline, which was built during the Soviet era, has a capacity of only 106 Bcf per year and has been inactive for the last 10 years. An investment of $20 million is needed to repair the line, while transportation of Iranian LNG to Nakhchivan is impossible without the construction of a new 28-mile pipeline segment from Khoi (Iran) to Culfa. LNG from Shah Deniz would be given to Iran over three years to compensate Iran's supply of LNG to Nakhchivan.

Natural Gas Exports

With the discovery of the Shah Deniz field in 1999, Azerbaijan's natural gas production potential expanded dramatically, setting the stage for the country to become a major net exporter of natural gas over the course of the next decade. International interest in Azerbaijan's natural gas sector has increased sharply due to Shah Deniz, and Azerigaz already has signed agreements with both Statoil and Royal Dutch/Shell to develop and export Azerbaijani natural gas. With the necessary infrastructure in place and the elimination of flaring, Azerbaijan's natural gas production could increase to as much as 1 Tcf by 2010.

On March 12, 2001, Azerbaijan signed its first major natural gas export deal when it concluded an agreement to supply Turkey with 89.2 Bcm (3.1 Tcf) of natural gas over a 15-year period, starting in 2004. Under terms of the deal,

Azerbaijan will supply Turkey with 70.6 Bcf in 2004, 106 Bcf in 2005, 177 Bcf in 2006, and 233 Bcf per year from 2007 to 2018. Natural gas for the deal is expected to come primarily from the as-yet undeveloped Shah Deniz field, with SOCAR acting as supplier on behalf of all the participants of the international consortium developing the field. In order to deliver this natural gas, a Baku-Erzurum pipeline is in development, one of several natural gas export pipeline options from the Caspian Sea region that have been proposed.

COAL

Azerbaijan has no significant coal deposits, nor any domestic coal production. Azerbaijan consumes only a small amount of coal, and consumption has declined from over 26,400 short tons in 1992 to just 1,100 short tons in 2000.

ELECTRICITY

Azerbaijan's power sector has an installed generating capacity of approximately 4.8 gigawatts (GW), consisting of seven thermal plants (which supply over 85% of generating capacity) and six hydroelectric plants. Built during the Soviet era, Azerbaijan's power infrastructure is generally in poor condition, with minimal public investment and maintenance since independence. The country's economic contraction during the mid-1990s, along with systemic problems--such as prices capped below the market rate and frequent non-payment by customers--have left Azerbaijan's power sector without sufficient capital to upgrade aging power-generation facilities.

In 2000, Azerbaijan produced 17.6 billion kilowatt-hours (Bkwh) of electricity and consumed 16.7 Bkwh, but because of the country's inefficient distribution network, energy losses amounted to around 20% of the electricity that was generated. In order to supply electricity to all parts of the country, Azerbaijan imports power from Russia, Turkey, Iran, and Georgia, and the country participates in energy exchanges as well.

Electricity supplies to the Azerbaijani exclave of Nakhchivan have been a recurring problem. Iran, which supplies nearly 60% of the exclave's electricity needs, cut power supplies from October 2000 to February 2001 until

Azerbaijan paid the first installment on its $45 million debt for supplies already delivered. In addition, Azerbaijan has run up a multi-million dollar debt to Turkey for electricity supplied to Nakhchivan. Azerbaijan is participating in an EU program to create a unified energy system for Azerbaijan, Georgia, and Turkey, and in April 2000, an agreement was signed to restore the power grids between Azerbaijan, Georgia, Russia, and Armenia. Azerbaijan and Turkey agreed that Azerbaijan would repay its debt by transmitting Russian and Azeri electricity back to Turkey via Georgia.

President Aliyev issued a decree in 1996 to transform the state power company, Azerenergy, into a state-owned, closed, joint-stock company, and issued a five-year program for privatization after the company's outstanding debts were paid. After a failed privatization of 16 distribution networks in 2000 (bids were received for only 4 networks), Azerbaijan decided to divide the national grid into five zones (Baku, Nakhchivan, North (Sumqayit), South (Ali Bayramli) and West (Ganja)), then form joint-stock companies at these regional grids and give them to foreign investors to manage. Power stations are to remain state-owned initially. In November 2000, the Ministry of State Property opened the tender packages for the privatization of *Bakuelectricshebeke* (Baku electric network).

Several projects are underway to restore and add new capacity to Azerbaijan's power sector. In May 2000, the country's 4,000-MW Yenikand hydroelectric station was finally completed, significantly boosting capacity. Construction originally began in 1985, but was suspended two years later and only resumed in 1996 with the aid of a $53 million loan from the World Bank. Reconstruction of the $41 million, 360-MW Mingechaur hydroelectric station on the Kura River was finished in 2001.

In December 2000, construction began on the $201 million Severnaya power plant, to be built with the help of Japanese companies Mitsui and Mitsubishi. Construction of the 400-MW power unit was 70% complete in April 2002, with a planned launch date in July 2002. In addition, in October 2000 the German KFW bank allocated the second credit tranche of $15 million for the

construction of substations and acquisition of technical equipment for Azerbaijan's power sector. Overall, analysts have estimated that the large-scale upgrades needed by Azerbaijan's power sector could cost $2.5 billion.

COUNTRY OVERVIEW

President: Heydar Aliyev (since June 18, 1993; re-elected to a second, five-year term on October 11, 1998)
Prime Minister: Artur Rasizade (since November 26, 1996)
Independence: August 30, 1991 (from Soviet Union); National holiday: Independence Day, May 28
Population (7/01E): 7.8 million
Location: Southwestern Asia, bordering the Caspian Sea, between Iran and Russia
Size: 33,436 square miles (slightly smaller than Maine)
Major Cities: Baku (capital), Ganja, Mingechaur, Nakhchivan, Stepanakert, Sumqayit, Yevlakh
Languages (1995E): Azerbaijani (Azeri) 89%, Russian 3%, Armenian 2%, other 6%
Ethnic Groups (1998E): Azeri 90%, Dagestani 3.2%, Russian 2.5%, Armenian 2% (almost all Armenians live in the separatist Nagorno-Karabakh region), other 2.3%
Religions (1995E): Muslim 93.4%, Russian Orthodox 2.5%, Armenian Orthodox 2.3%, other 1.8%. Note: religious affiliation is still nominal in Azerbaijan; percentages for actual practicing adherents are much lower.

ECONOMIC OVERVIEW

Minister of Economic Development: Farhad Aliyev
Minister of Finance: Avaz Alakbarov
Currency: Manat
Exchange Rate (1/02): U.S. $1 = 4,770 manats
Nominal Gross Domestic Product (GDP) (2001E): $5.2 billion; **(2002E):** $5.7 billion
Real GDP Growth Rate (2001E): 7.5%; **(2002E):** 7.0%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E):

2.8%; **(2002E):** 3.5%
Official Unemployment Rate (2001E): 1.3%; **(2002E):** 1.4%
Current Account Balance (2001E): $171 million; **(2002E):** $200 million
Major Trading Partners: Turkey, Russia, Georgia, Italy, Iran, Ukraine, United Arab Emirates
Merchandise Exports (2001E): $2.32 billion; **(2002E):** $2.65 billion
Merchandise Imports (2001E): $1.62 billion; **(2002E):** $1.86 billion
Merchandise Trade Balance (2001E): $707 million; **(2002):** $790 million
Major Exports: Oil and natural gas (70%), machinery, cotton, foodstuffs
Major Imports: Machinery and equipment, foodstuffs, metals, chemicals
Gold and Foreign Exchange Reserves (2000E): $681 million
External Debt (12/01E): $1.2 billion

ENERGY OVERVIEW

Minister of Fuel & Energy Development: Macid Karimov
President, State Oil Company of Azerbaijani Republic (SOCAR): Natik Aliyev
Proven Oil Reserves (1/1/02E): 1.2 billion barrels
Oil Production (2001E): 311,200 barrels per day (bbl/d); **(2002E):** 310,000 bbl/d
Oil Consumption (2001E): 136,000 bbl/d
Net Oil Exports (2001E): 175,200 bbl/d
Crude Oil Refining Capacity (1/1/01E): 442,000 bbl/d
Natural Gas Reserves (1/1/02E): 4.4 trillion cubic feet (Tcf)
Natural Gas Production (2000E): 200 billion cubic feet (Bcf)
Natural Gas Consumption (2000E): 200 Bcf
Coal Production (2000E): none
Coal Consumption (2000E): minimal
Electricity Generation Capacity (2000E): 4.8 gigawatts
Electricity Generation (2000E): 17.6 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 16.7 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Ecology & Natural Resources: Huseyngulu Bagirov

Total Energy Consumption (2000E): 0.53 quadrillion Btu* (0.1% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 12.5 million metric tons of carbon (0.2% of world carbon emissions)
Per Capita Energy Consumption (2000E): 66.0 million Btu (vs U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 1.6 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 155,556 Btu/$1990 (vs U.S. value of 10,918 Btu/$1990)**
Carbon Intensity (2000E): 3.67 metric tons of carbon/thousand $1990 (vs U.S. value of 0.17 metric tons/thousand $1990)
Sectoral Share of Energy Consumption (1998E): Industrial (38.6%), Residential (9.2%), Transportation (48.9%), Commercial (3.3%)
Sectoral Share of Carbon Emissions (1998E): Industrial (49.3%), Residential (11.2%), Transportation (35.1%), Commercial (4.4%)
Fuel Share of Energy Consumption (1999E): Oil (56.5%), Natural Gas (39.0%), Hydroelectric (4.2%)
Fuel Share of Carbon Emissions (1999E): Oil (48.9%), Natural Gas (51.1%)
Renewable Energy Consumption (1998E): 20.4 trillion Btu* (22% increase from 1997)
Number of People per Motor Vehicle (1998): 21.3 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 16th, 1995). Ratified the Kyoto Protocol on September 28, 2000.
Major Environmental Issues: local scientists consider the Abseron Yasaqligi (Absheron Peninsula) (including Baku and Sumqayit) and the Caspian Sea to be the most ecologically devastated area in the world because of severe air, water, and soil pollution; soil pollution results from the use of DDT as a pesticide and also from toxic defoliants used in the production of cotton.
Major International Environmental Agreements: A party to the

Conventions on Biodiversity, Climate Change, Climate Change-Kyoto Protocol, Desertification, Endangered Species, Marine Dumping, Ozone Layer Protection. Has signed, but not ratified: none.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY
Organization: State Oil Company of Azerbaijani Republic (SOCAR); Azerigaz (state natural gas distribution company); Azerenergo (state electric company)
Major Oil Ports: Baku
Oil Export Pipelines: Baku-Novorossiisk (via Russia; "early oil" northern route), Baku-Supsa (via Georgia; "early oil" western route)
Major Oil Refineries (Capacities 1/1/02E): Azerineftyag (Baku) (230,000 bbl/d), and Azerneftyanajag (New Baku) (212,000 bbl/d)
Major Power Plants: Yenikand (4,000 megawatts, MW) (hydro), Azerbaijan Station near Mingechaur (2,100 megawatts, MW), Ali-Bayramli (1,100 MW)

Sources for this report include: Associated Press, BBC Monitoring International Reports, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, Economist Intelligence Unit ViewsWire, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, ITAR-TASS News Agency, Oil and Gas Journal, Petroleum Economist, Platt's Oilgram News, Radio Free Europe/Radio Liberty, Reuters, U.S. Department

of Commerce's Business Information Service for the Newly Independent States (BISNIS), U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, World Markets Online.

Links

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Energy Information Administration

December 2001

Germany

Germany is one of the world's largest energy consumers. Because it has limited indigenous energy resources (except for coal), Germany imports most of its energy. Although the country is a major coal producer, it is a net coal importer.

The information contained in this report is the best available as of December 2001 and is subject to change.

GENERAL BACKGROUND

Germany is one of the largest economies in the world, a founding member of the European Union (EU), a North Atlantic Treaty Alliance (NATO) member, and a member of the Group of Seven (G-7) industrialized nations. It joined the common European currency, the euro, on January 1, 1999, and Frankfurt is the seat of the European Central Bank. The German mark will disappear in the first few months of 2002 as people trade in their marks for the new euro coins and currency.

Germany experienced slower economic growth during 2001 as compared to 2000, and may be on the verge of a slight contraction, according to a report published in October 2001 by Germany's top six economic research institutes. The events of September 11 had a negative effect on the entire world economy, and

recent German government estimates are that growth in 2001 may be just 0.75%. In September, business confidence in Germany fell to its lowest level since 1993. Export-led growth has been diminished as the global economy, and that of the United States in particular, loses momentum. Unemployment, a major issue in German politics in recent years, has decreased slightly since its high point in 1998. However, the current economic slowdown indicates that unemployment likely will not fall any further in the next 12 months.

Energy in Germany

German has relatively insignificant domestic energy sources and is heavily import-reliant to meet its energy needs. Coal accounted for 47% of domestic energy production in 1999, nuclear power 30%, natural gas 14%, renewable sources (including hydro) 6%, and oil 2%. However, oil accounted for 41% of consumption.

Energy policy in Germany is influenced heavily by EU regulations. The EU requires privatization and competition in member countries' energy markets, and Germany has been a leader in developing competitive energy markets.

Following reunification of the country in 1990, the major task of German energy policy was to merge successfully the radically different energy sectors of the East and West. West Germany had a diversified and mainly privately-owned system of energy supply with a high standard of energy efficiency and a commitment to environmental protection. In contrast, East Germany's energy sector was highly centralized, predominantly state-owned, and mainly dependent upon relatively "dirty" lignite (brown coal) as its primary fuel. To date, a great deal of progress has been made in conforming the former East Germany's energy sector to the standards of the West in the areas of privatization and environmental regulation.

OIL

Germany consumed about 2.8 million barrels per day (bbl/d) of oil in 2000, nearly all of which it imported, making Germany the third-largest oil importer in the world. German oil imports in 2000 came primarily from Russia (29%), Norway (18%), United Kingdom (13%), and the Libya (11%). German imports from Russia have remained unchanged in recent years. However, OPEC's share of German imports has decreased, while the share of North Sea oil from Norway and the United Kingdom has increased. For the first six months of 2001, preliminary estimates show Russian crude oil maintaining the same level as 2000, but imports from OPEC declining from 26% to 22% of total imports into Germany.

Germany produced around 64,000 bbl/d of crude oil in 2000, of which 16,000 bbl/d came from the German North Sea. Higher world oil prices in 2000 spurred a small increase in domestic crude oil production. Veba Oel is Germany's largest upstream company, with interests in 13 countries, including Germany, and production of about 160,000 barrels of oil equivalent per day.

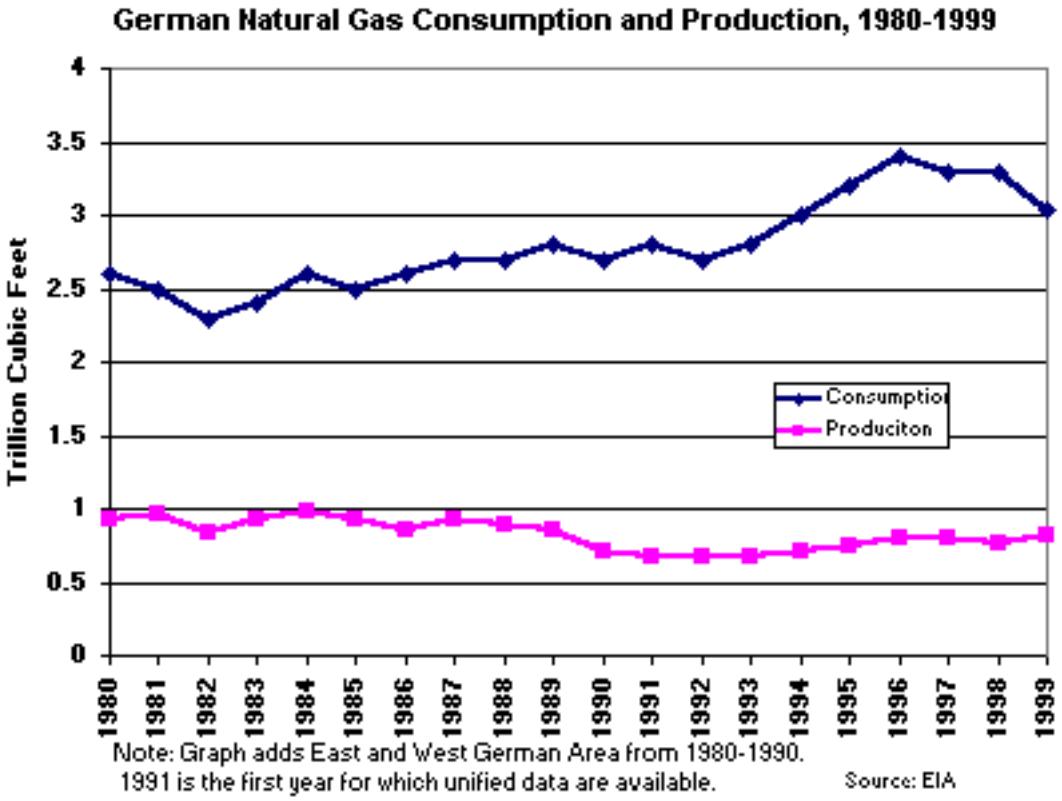
Germany's oil consumption was essentially unchanged in 2000 as compared to 1999. With the aid of hefty federal taxes on gasoline consumption, Germany had decreased its oil consumption in recent years,

with lower consumption in 1999 than in any year since unification. For instance, Germans pay about four times more for motor gasoline than Americans, despite having the most competitive retail gasoline market in Europe. German refinery throughput increased 1% in 2000, and refinery capacity utilization was at 95%.

The German downstream sector is in the process of completing two large mergers. In April 2001, Royal Dutch Shell and one of Germany's largest energy companies, RWE, agreed to form a new 50:50 venture called Shell & Dea Oil. The new company is managed by Shell, and in 2004 Shell's share will increase to 51%, and Shell will have the option to buy the remaining 49%, which it is expected to do. The new company will have about a 23% market share for gasoline stations and is poised to become Germany's largest refinery operation with capacity of about 460,000 bbl/d. However, in July 2001, BP acquired a majority stake (51%) in Veba Oel from E. On. Veba Oel, in addition to upstream assets valued at $2 billion, owns the Aral network of gasoline stations, which has a 25% market share, and refinery capacity of about 300,000 bbl/d. In return, BP gave E. On a majority stake (51%) of its 25.5% holding (through holding company Gelsenberg) of German gas distributor Ruhrgas, $1.63 billion in cash, and agreed to assume debts of $950 million. BP and E. On have the option to acquire the remaining stakes in Veba and Gelsenberg, respectively. When the second deal was announced, both deals came under increasing scrutiny by EU and German officials. The European Commission has endorsed a preliminary finding of risk of "collective dominance" by the German cartel office, to which it has delegated responsibility for assessing the downstream market effects. The European Commission is retaining responsibility for a 4-month investigation launched in late August on the effect of the mergers on the petrochemical industry.

NATURAL GAS

Germany is the European Union's second largest consumer of natural gas, after the United Kingdom. Germany produces insufficient natural gas to satisfy domestic consumption and satisfies most of its demand through imports. In 1999, the country produced 0.82 trillion cubic feet (Tcf) of natural gas from proven reserves of 11.5 Tcf, while consuming 3.0 Tcf (a decline of 300 billion cubic feet (Bcf) from 1998). This decline appears to have continued into 2000, as natural gas import prices rose steadily, and German gas suppliers instead drew down stored natural gas that had been purchased at cheaper prices. Although overall natural gas consumption fell 1.2% from 1998 to 1999, power sector usage fell a much larger 7%. E. On, Germany's second-largest largest utility, has asserted that power sector usage of natural gas fell even further in 2000, as it became cheaper to import electricity and maximize output from coal-fired facilities. In 1999, residential and other non-commercial consumers accounted for 53% of total demand, industry for 38%, and power stations, 9%. In 2000, Russia provided 37% of Germany's consumption, the Netherlands 26%, Norway 14%, and Denmark 1%. Natural gas consumption accounted for about 21% of total energy consumption in Germany in 1999. This share is expected to rise over the decade, especially for electric power generation as nuclear power is phased out. In September 2000, the *Deutsches Nordseekonsortium* (German North Sea Consortium), which is made up of Wintershall (40%, operator), BEB Erdgas und Erdoel (40%), BASF (12%), and RWE-DEA (7%), began production. The first offshore natural gas project in the German North Sea, the field is located about 190 miles from the German coast. New pipelines will transmit the anticipated 3.3 million cubic meters (116.5 million cubic feet) per day of production. The field is expected to produce for 16 years.



Ruhrgas remains Germany's dominant natural gas transmission company, accounting for about 60% of all natural gas sales. Years of Ruhrgas's monopolistic control of Germany's natural gas market have left Germany with a highly developed gas infrastructure. E. On, which already owns 42% of Ruhrgas through the deal with BP mentioned above and through E. On's partial ownership of another holding company of Ruhrgas, Bergemann, announced in November 2001, that it intends to buy the remaining shares of Bergemann, lifting E. On's share of Ruhrgas to 60%. E. On also sells to 35% of Germany's natural gas customers through its stakes in smaller companies Contigas and Thuga. E. On's ownership of Ruhrgas is already being investigated by the German cartel office, but perhaps more problematic is the fact that the outstanding shares of Bergemann are controlled by German coal group RAG, which is part-owned by E. On's rival company RWE. RWE may attempt to block the deal unless E. On gives RWE a larger share of RAG, of which E. On also is part-owner. Ruhrgas itself announced in October 2001, that it plans to bid for the gas division of Hungary's state-owned oil and gas group MOL.

Competition in Germany's natural gas market has developed slowly. Ruhrgas's main competitor, Wingas, was formed in 1993 by a joint venture between BASF's Wintershall (65%) and Russia's Gazprom (35%). Now, with its own domestic pipelines and links to export supply lines, Wingas has gained market share (19%), while Ruhrgas's share has decreased. Eni of Italy and Energie Baden-Wurttemberg (EnBW) may also bring more competition to the German gas market through their partnered acquisition of a majority stake in Gasversogung Suddeutschland (GVS). GVS currently gets 85% of its supply from Ruhrgas and 15% from Wingas, but the new Eni-EnBW holding company would likely have Eni supplying Libyan and Algerian gas to GVS. This acquisition of GVS is not yet certain, as there are remaining political and business obstacles.

Although Germany has one of the most liberalized energy sectors in the EU, full liberalization of the German natural gas market has not emerged as expected. According to EU law, member countries' natural gas transmission systems had to be open to third party access as of August 2000. While a German law was in place confirming a legal right for third party access, in practicality, new entrants have had difficulty gaining access. The creation of an independent regulator by the government is seen as key to making the market more accessible.

Pipelines

Germany is both a major destination point and major transit center for Europe's natural gas pipelines. Germany has five major pipelines on land, three from the North Sea to its coast, and several in the construction and planning stages. Pipelines from the Czech Republic transport Russian natural gas. The existing pipelines include: 1) The MEGAL pipeline from the Czech Republic to France through Germany, with annual capacity of 777 billion cubic feet (Bcf), 2) the TENP pipeline from the Netherlands to Germany and onward to Switzerland and Italy, with an annual capacity of 247 Bcf, 3) the STEGAL pipeline from the Czech Republic to Germany, with an annual capacity of 283 Bcf, 4) the NETRA pipeline from Etzel/Wilhelmshaven to Steinitz/Bernau, with an annual capacity of 706 Bcf and 5) the MIDAL pipeline from the port of Emden to Ludwigshafen with an annual capacity of 459 Bcf. The pipelines that bring Norwegian natural gas ashore are Norpipe, which lands at Emden, and Europipe I & II, which land at Dornum. From the Dornum receiving station, the natural gas is linked to either the NETRA pipeline or the metering station at Emden, where the MIDAL pipeline begins. The TENP pipeline can also bring in UK gas by way of the Netherlands. Wingas, which already owns the MIDAL and STEGAL pipelines, is planning to construct a pipeline with a capacity of 353-424 Bcf per year from Heppenheim in Southwest Germany to the states of Badem-Wurttemburg and Bavaria in Southeastern Germany. Ruhrgas is the largest shareholder in the MEGAL, TENP, and NETRA pipelines, though it has a majority stake only in the TENP pipeline. Ruhrgas, Fortum of Finland, and Wingas agreed in April 2001, to jointly develop plans to build a natural gas pipeline from Russia to Germany via the Baltic Sea.

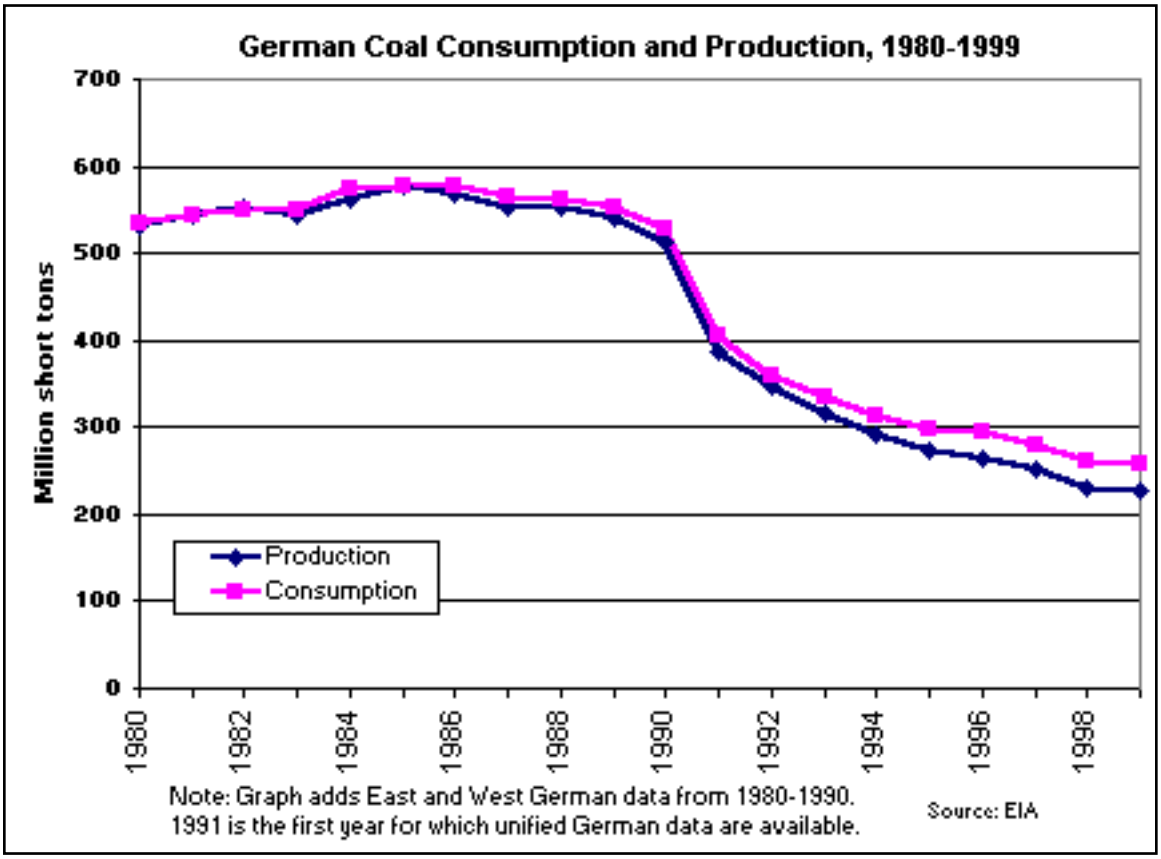
The large volumes of natural gas entering Germany, particularly on the Northwest coast around Emden, have given rise to efforts to establish Europe's third major natural gas hub at Bunde near the Dutch border. This is the point where the pipeline system of Gasunie of the Netherlands links up to the German networks of Ruhrgas, Wingas, and BEB. Spot trading by about a dozen companies is already occurring in this area, although volumes are small so far. Its location is in close proximity to where very large volumes of natural gas come into Germany, combined with European Commission proposals to unbundle integrated gas companies in the EU make the formation of an important hub likely. A conference was held in May 2001, on the subject of fostering natural gas trade at Bunde, which was attended by 40 companies, including all of Germany's major players.

COAL

Coal is Germany's only major domestic fuel source, accounting for 23% of energy consumption in 1999. Over 75% of German coal production is used for electricity generation, and coal accounts for over 50% of electricity generation. Hard coal production is expensive in Germany relative to other major coal producers, because German coal is located deep underground. Hard coal production has remained a viable industry only through heavy subsidization, which is being reduced, but not ended. Lignite, or "brown coal," production, however, is inexpensive in Germany. Germany is the world's largest lignite producer, with about one-fifth of global output, though output of lignite, most of which comes from the former East Germany, has fallen by about 40% since reunification.

In March 1997, the German government, the mining industry, and the unions reached an agreement on the future structure of subsidies to the German hard coal industry. Subsidies to the industry are to be

reduced from over DM10 billion ($5.5 billion) in 1997 to DM5.5 billion ($3 billion) by 2005. The agreement called for closure of 7-8 of Germany's 19 hard coal mines, resulting in an estimated decline in employment from 76,000 miners in 1997 to 36,000 by 2005. As of December 2000, 12 hard coal mines in Germany were still in operation.



In October 2000, the EC Energy Commissioner Loyola de Palacio demanded that Germany rework this subsidization scheme or risk legal action. The EC claimed that too much of that amount will be spent on subsidizing continuing production, and not enough devoted to ending production. This dispute was resolved in November 2000, by allocating part of the annual coal subsidy volume to a different category of coal aid, namely, to "mines that will definitely be closed at some point." In July 2001, the EC set out new proposals to maintain a significant coal industry in the EU (for reasons of energy security) that will allow Germany to provide billions of euros in aid over the coming years. Specifically, under the proposals German aid would fall to 2.8 billion euros in 2005, which does not differ greatly from the domestic agreements of 1997. The most recent aid package of 2 billion euros from January 1, 2002 to July 23, 2002, was approved by the EC in October 2001.

Decreasing coal production has brought about changes in the industry's organization. Two major producers, Saarbergen and Ruhrkohle Bergbau, merged to form Deutsche Steinkohle (DSK), which accounts for 96% of German production. DSK is part of the larger RAG group, which intends to diversify its holdings and focus less on coal as the sector shrinks in coming years. RAG is itself owned by E. On, RWE, Thyssen, and two holding companies.

As domestic production declines, Germany is emerging as a significant coal importer. Imports of hard coal, coke, and briquettes increased by 8.5% in 1999-2000, and are estimated to have increased even more in the first few months of 2001. The largest supplier is Poland, followed by Australia, South Africa, and Colombia, among others. The Federation of German Coal Importers expects German hard coal imports to exceed domestic production in 2001 or 2002, and to double over the next 20 years, as nuclear power is phased out and domestic production declines.

Germany's lignite production is separate from hard coal production. Lignite was the most important fuel in the former East Germany, and East Germany had been producing about three times as much lignite as West Germany in the years prior to reunification. Since reunification, wasteful and environmentally damaging mining methods practiced during Communist rule have been reformed. The industry also has been privatized. Lignite production in Germany fell from 308 million short tons (Mmst) in 1991 to 178 Mmst in 1999. Rheinbraun, a subsidiary of RWE, is responsible for most of German lignite production, and most of its lignite is used to produce electricity in RWE's power generation plants.

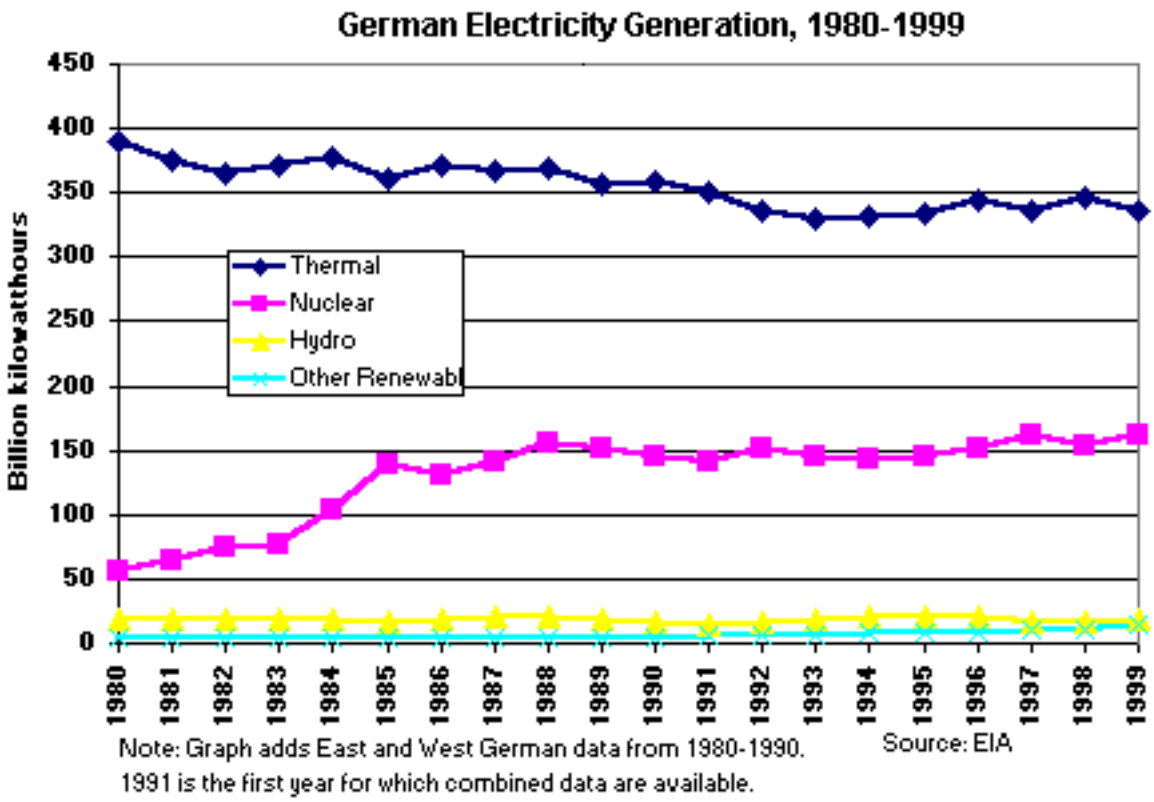
RAG has founded a new company called Minegas to exploit the mine gas from operational and closed mines for electricity generation. Minegas has already formed a consortium with several other German companies and a partnership with RWE. The target is to generate 450 gigawatts (GW) per year from mine gas.

ELECTRICITY

Germany has Europe's largest electricity market. In 1999, Germany generated 531.4 billion kilowatt hours (bkwh) of electricity, two-thirds of which came from fossil fuels (mostly coal), with the other other third coming mostly from nuclear power along with small amounts of hydropower and other renewable sources. Although Germany produced more electricity than it consumed, the country was a small net electricity importer, because of transmission losses, proximity to foreign sources of generation, etc. Germany has about 2,800 power plants and considerable excess generation capacity. The International Energy Agency predicts slow power demand growth in coming years. Major electricity companies recently have announced intentions to decrease generation capacity and output, and new power plant construction is at record lows. There is a new gas-fired, combined-cycle power plant with a capacity of 400 megawatts (MW) that was inaugerated by Kraftwerke Mainz-Wiesbaden near Frankfurt in March 2001.

The industry is undergoing changes in fuel mix and in organization. Efforts continue to phase out nuclear power and to increase reliance on renewable energy sources, most notably wind power, and on natural gas. RWE is developing fuel cell technology for electricity generation that it hopes to have functioning by 2004.

Sector Organization



In step with EU legislation, the German power market has become one of the most competitive in Europe. Liberalization of the electricity sector has progressed via agreements among major participants in the market and is not overseen by any regulatory body (like the natural gas sector). Some German market groups and the European Commission have called for an energy regulator, but so far the government has only created a six-member division of the cartel office dedicated to handling complaints about the electricity sector. About one million of Germany's 40 million electricity customers have switched to competitive suppliers. About 1,000 terrawatthours were traded in 2000. Liberalization has resulted in lower consumer prices and decreased employment in the industry, and is now sparking a wave of consolidation.

Six major electricity generation companies have dominated the German market in recent years, accounting for about 80% of generation. Major mergers are re-shaping the industry, potentially reducing the number of major players from six to three. RWE, the largest electricity company in Germany, has acquired VEW, the country's sixth-largest electricity producer. E. On, Germany's second largest electricity company, is set to aquire UK energy provider Powergen in a $16.9 billion deal. Powergen owns U.S. utility LG&E Energy, so when the deal is complete E. On will be world's second-largest energy provider after Electricite de France, and will have a significant presence in the U.S. E. On and Verbund of Austria agreed in July 2001, to combine their hydroelectric generation assets into one company, European Hydro Power, which would own about 200 plants with a total of 9,600 MW. In June 2001, the formation of Germany's third-largest energy company was announced by Hamburgische Electricitaets-Werke (HEW). A new holding company is being formed that is expected to be complete by 2003 that will control HEW, Berlin utility BEWAG, eastern German generation group VEAG, and lignite-mining company LAUBAG. Through a series of acquisitions, the company will be owned by HEW, Vattenfall of Sweden, and Mirant of the United States

The utility market is highly fragmented in Germany, with about 70 regional utilities and 900 municipal utilities, which together account for about 20% of power generation and about two-thirds of distribution. The Deutsche Verbundgesellschaft (DVG), which groups the main supra-regional utilities and deals with

national and international interconnections issues, and the Vereinigung Deutscher Elektrizitaetswerke (VDEW), which deals with economic and other technical issues. The regional utilities are grouped in the Arbeitsgemeinschaft Regionaler Energie Versorgungsunternehmen (ARE), the Stadtwerke are grouped in the Verband Kommunaler Unternehmen (VKU), and industrial producers are in the Vereinigung Industrielle Kraftwirtschaft (VIK).

Despite the overall success of liberalization, third party access to transmission networks remains a contentious issue. The *Verbandervereinbarung* that determines access to the grid system was first agreed in May 1998 and left transmission control mostly in the hands of the six major companies. After much criticism, a new Verbandervereinbarung was agreed in December 1999. This agreement has encountered even more criticism than its predecessor, and EU competition authorities have expressed concern. The most criticized aspects of the agreement include a lack of price transparency and the division of the German market into two distinct trading zones.

The German government has been critical of EU member governments that have not taken steps to open their power sectors in accordance with EU law. Currently, German electricity companies do have the right to block electricity imports from countries that deny access to foreign companies. The Minister of Economics, Werner Mueller, has proposed that German energy law be amended to extend the right to invoke bans, known to the government as "reciprocity clauses." However, the European Association of Transmission System Operators (ETSO) is urging Germany to adopt its policy of socializing network access costs such that costs of flows of electricity between grids is passed on to all users to promote exchange. Germany wants to pass export costs on to just exporters. If Germany does not agree to ETSO's policy, there is the possibility of Germany being excluded from the system. A decision will have to be taken by ETSO by the end of the year.

Nuclear Power

Currently, Germany ranks fourth worldwide in installed nuclear capacity, behind the United States, France, and Japan. Germany's 19 nuclear plants comprise about 21% of Germany's electric generation capacity, and about 30% of actual generation. E. On, RWE, HEW, and EnBW own nuclear generation capacity, with E. On holding stakes in 11 of Germany's 19 nuclear power reactors.

Nuclear power has become controversial since the September 1998 elections. The Greens, the environmental party that is part of the ruling alliance, are staunchly opposed to the continued use of nuclear power. Chancellor Schroeder had decided to close all 19 nuclear reactors in 2005, but he has since amended his position. The government formally signed an agreement with utility companies in June 2001 to gradually phase out nuclear power. Each nuclear plant is allowed to produce a finite amount of electricity, and plants will have a life span of 32 years. The deal could see the total elimination of nuclear power by 2021, as the newest nuclear plant opened in 1989. Generation volumes are transferable; if an older plant closes before reaching its production ceiling, its remaining allowable production can be transferred to a new plant.

There are few economically viable alternatives to quickly replace such a significant portion of the fuel

mix, especially in the wake of power-sector liberalization. As European markets become more liberalized and more price-sensitive, replacing the mostly amortized plants will prove difficult. Over the longer term, however, high costs (high fixed costs, long depreciation periods and long annual operating times) associated with nuclear generation could work to decrease nuclear generation's role in Germany's power sector. Nuclear installations currently are initiating programs to reduce production costs and waste disposal costs in order to become more price-competitive. In October 2000, E. On and RWE announced intentions to close a number of their less competitive (in terms of price) nuclear power plants. Some executives in Germany's nuclear industry have claimed that the June 2001 agreement is not irreversible, and that an electricity shortage and a change in the political climate might lead to a renewal of nuclear energy.

ENVIRONMENT

Germany has a strong commitment to protecting its environment. It has actively promoted the use of renewable energy, both under the Kohl government with the Electricity Feed Law, and now under Schroeder's government with eco-taxes. In Germany's eco-tax regime, energy tax (energy taxes are slated to increase 10% over the next three years) revenue is used to fund renewable projects. However, in late October 2001, the Chancellor's chief economic advisor indicated that these ecological taxes may be suspended for a year or two as a way to provide a stimulus to economy.

In 1999, Germany emitted 236.9 million metric tons of carbon from the consumption of fossil fuels. Germany ranks third in total carbon emissions within the G-7, after the United States and Japan. Germany signed the Framework Convention on Climate Change in Rio de Janeiro in June 1992 and ratified it on December 9, 1993. Signers of the agreement pledged to stabilize per capita CO_2 emissions in the year 2000 and beyond at 1990 levels. Under the Kyoto Protocol of December, 1997, Germany would have to go even further by reducing carbon emissions 8% by 2008-2012. This will be made more achievable given the sharp drop in total German carbon emissions since 1990, due mainly to decreased consumption of energy overall (and in particular lignite) in the former East Germany.

Sources for this report include: CIA World Factbook; Dow Jones; Economist Intelligence Unit ViewsWire; Petroleum Intelligence Weekly; Financial Times; Economist; Petroleum Economist; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

President: Johannes Rau (elected May 1999)
Chancellor: Gerhard Schroeder (elected September 1998)
Independence: January 18, 1871 (reunification of West and East Germany took place on October 3, 1990)
Population (2001E): 83 million
Location/Size: Central Europe, bordering the Baltic Sea and the North Sea, between the Netherlands and Poland, south of Denmark/137,821 square miles (slightly smaller than Montana)
Major Cities: Berlin (national capital since 10/3/90), Hamburg, Munich, Cologne, Frankfurt, Essen, Dortmund, Stuttgart

Language: German
Ethnic Groups: German 91.5%, Turkish 2.4%, other 6.1% (made up largely of Serbo-Croatian, Italian, Russian, Greek, Polish, Spanish)
Religions: Protestant 38%, Roman Catholic 34%, Muslim 1.7%, unaffiliated or other 26.3%
Defense (8/98): Army, 230,600; Navy, 26,700; Air Force, 76,200 (including conscripts)

ECONOMIC OVERVIEW

Finance Minister: Hans Eichel
Currency: Deutsche Mark (DM)
Exchange Rate (12/02/01): 1 US Dollar = 2.1981 DM
Gross Domestic Product (GDP, nominal, 2000E): $1.87 trillion **(2001E):** $1.89 trillion
Real GDP Growth Rate (2000E): 3.0% **(2001E):** 1.1%
Inflation Rate (consumer prices, 2000E): 1.9% **(2001E):** 2.7%
Unemployment Rate (2000E): 9.6% **(2001E):** 9.5%
Exports of Goods (2000E): $549 billion
Imports of Goods (2000E): $492 billion
Major Trading Partners (2000): France, U.S., U.K., Italy, Netherlands
Major Export Products (2000): Machinery and transport equipment, manufactured goods, chemicals
Major Import Products (2000): Machinery and transport equipment, manufactured goods, other finished goods, fuels

ENERGY OVERVIEW

Minister of Economics: Werner Mueller
Proven Oil Reserves (1/1/01E): 380 million barrels
Oil Production (2000E): 139,000 barrels per day (bbl/d), of which 64,000 bbl/d was crude oil
Oil Consumption (2000E): 2.76 million bbl/d
Net Oil Imports (1999E): 2.7 million bbl/d
Natural Gas Reserves (1/1/01E): 11.5 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 0.82 Tcf
Natural Gas Consumption (1999E): 3.0 Tcf
Coal Reserves (12/31/96E): 73.9 billion short tons
Coal Production (1999E): 226 million short tons (Mmst)
Coal Consumption (1999E): 258 Mmst
Net Coal Imports (1999E): 32 Mmst
Electric Generation Capacity (1/1/99E): 108 gigawatts
Electricity Production (1999E): 531.4 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Minister for Environment: Juergen Trittin
Total Energy Consumption (1999E): 13.9 quadrillion Btu* (3.6% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 229.9 million metric tons of carbon (3.7% of world total carbon emissions)
Per Capita Energy Consumption (1999E): 170.4 million Btu (vs U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 2.8 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 7,280 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 0.12 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (41.9%), Residential (24.2%), Transportation (21.5%), Commercial (12.3%)
Sectoral Share of Carbon Emissions (1998E): Industrial (37.4%), Transportation (25.6%), Residential (24.5%), Commercial (12.5%)
Fuel Share of Energy Consumption (1999E): Oil (41.4%), Coal (23.2%), Natural Gas (21.2%)
Fuel Share of Carbon Emissions (1999E): Oil (45.1%), Coal (36.3%), Natural Gas (18.6%)
Renewable Energy Consumption (1998E): 395 trillion Btu* (5% increase from 1997)
Number of People per Motor Vehicle (1998): 1.9 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 9th, 1993). Under the negotiated Kyoto Protocol (signed on April 29th, 1998, but not yet ratified), Germany, as a member of the European Union, has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Emissions from coal-burning utilities and industries and lead emissions from vehicle exhausts (the result of continued use of leaded fuels) contribute to air pollution; acid rain, resulting from sulfur dioxide emissions, is damaging forests; heavy pollution in the Baltic Sea from raw sewage and industrial effluents from rivers in eastern Germany; hazardous waste disposal.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands, Whaling . Has signed, but not ratified, Air Pollution-Persistent Organic Pollutants.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999.

ENERGY INDUSTRIES

Major Energy Companies: *Oil:* Deutsche Shell, Esso, Ruhr Oel; *Natural Gas:* Ruhrgas, Wintershall/Wingas; *Coal:* DSK, RAG; *Electricity:* RWE, Viag, Veba
Major Refineries (crude capacity, bbl/d): Karlsruhe (285,800), Bayernoil (258,000), Schwedt (230,000), Gelsenkirchen (227,000), Leuna (214,000), Wilhelmshaven (225,000), Godorf (170,000), Wesseling (140,000), Esso Ingolstadt (105,000)

For more information from EIA on Germany, please see:
EIA - Country Information on Germany

Links to other U.S. Government sites:
CIA World Factbook - Germany
U.S. Department of Energy's Office of Fossil Energy's International section - Germany
U.S. Department of Energy on German Nuclear Sector
U.S. State Department's Consular Information Sheet - Germany
U.S. State Department's Country Commercial Guide - Germany
U.S. State Department Background Notes on Germany
U.S. Embassy in Germany

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Germany's Nuclear Energy Policy Briefing Paper
European Commission Directorate General XVII (Energy)
International Energy Agency's Germany 1998 Review
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File last modified: December 5, 2001

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Country Analysis Briefs

February 2002

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Coal | Electricity | Environment | Profile | Links

Canada

Canada is a net exporter of oil, natural gas, coal, uranium, and hydropower. It is one of the most important sources of U.S. energy imports.

Note: Information contained in this report is the best available as of February 2002 and can change.

BACKGROUND

Canada is expected to show a small decline in gross domestic product (GDP) in the first quarter of 2002, but the country's economy is expected to rebound quickly. Like its southern neighbor, the United States, the Canadian economy suffered in 2001 from the sharp decline in its technology sector. In addition to the

adverse effects of the domestic high technology industry collapse, slower world economic growth, and especially slow (or negative) growth in the United States, are having negative ramifications on the highly trade-dependent Canadian economy.

Economists have credited Canada for making sound tax and interest rate decisions that will help lift the country from its small recession. If the U.S. economy recovers in the second half of 2002, as many predict, the Canadian economy is predicted to grow by 1.1% in 2002.

ENERGY OVERVIEW

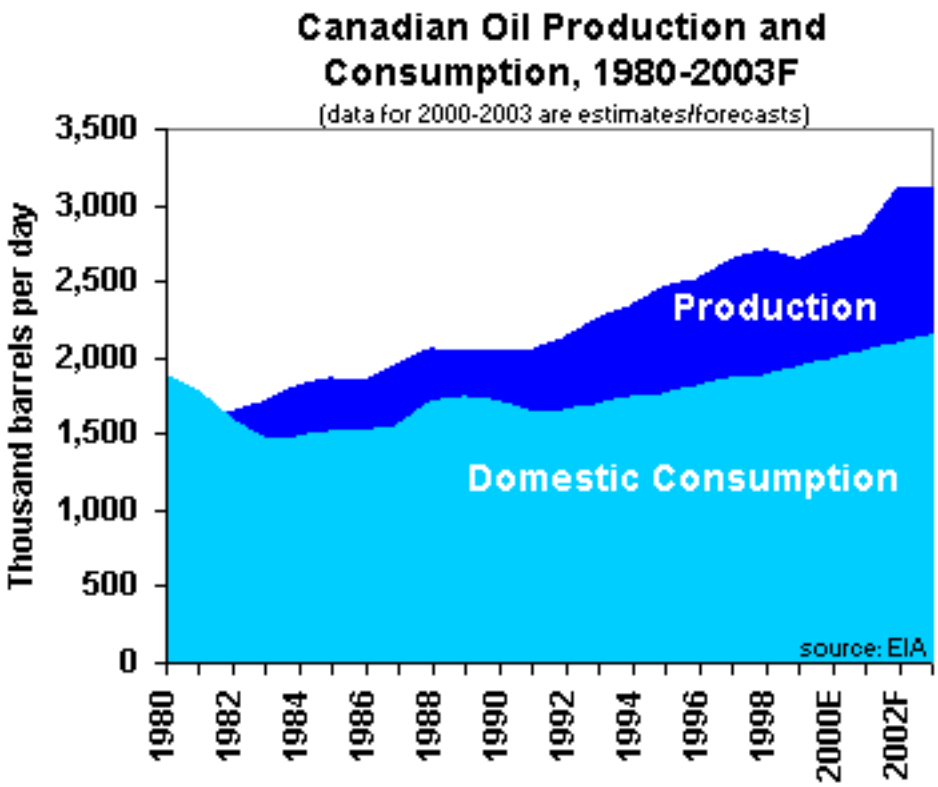
Canada was the fifth-largest energy producer in the world in 1999, behind the United States, Russia, China, and Saudi Arabia. Over the past two decades, Canada has become a significant net energy exporter. In 1999, about 30% of Canadian energy production was exported, with the United States by far its main customer. From January-November 2001, the United States imported more oil (including crude oil and petroleum products) from Canada than from any other country. The United States consumed 3.155 trillion cubic feet (Tcf) of Canadian natural gas in the first eleven months of 2001, with 93% of total U.S. gas imports coming from Canada. In 1999, about 36% of Canada's primary energy production was natural gas, followed by oil (23%), hydropower (20%), coal (11%), and nuclear power (4%). Over two-thirds of Canada's energy is produced in the province of Alberta.

Canada also is a significant energy consumer and a member of the International Energy Agency (IEA). It was the world's sixth-largest energy consumer in 1999, roughly on par with India in terms of total energy consumption.

The Canadian energy industry is undergoing a period of reorganization, with consolidation in the oil and natural gas sectors and privatization in the electricity sector. While geography inhibits the development of a national electricity market within Canada, there is significant trade with the United States and potential for strong north-south regional markets, involving several

Canadian provinces and adjacent U.S. states.

OIL



Canada has proven conventional oil reserves of 4.4 billion barrels, as of January 2002, a 152 million barrel increase over January 2001 levels. Oil production averaged 2.8 million barrels per day (bbl/d) during 2001, with estimated consumption of 2.0 million bbl/d. The province of Alberta, located in western Canada, is by far the country's leading oil producer. While Alberta's light oil reserves are declining (the province now contains an an estimated 45% of the country's light oil reserves), there are huge oil sands deposits. Meanwhile, projects and potential projects in other provinces are shifting the oil industry focus to include the eastern and northern parts of the country.

Canada is a major source of U.S. oil imports. From January through November 2001, the United States imported 1.8 million bbl/d of crude oil from Canada (1.3 million bbl/d of which was crude oil). This makes Canada the top petroleum supplier to the United States and the third-largest supplier of crude oil imports (behind Saudi Arabia and Mexico, and ahead of Venezuela). Canada has been the top supplier to the United States of refined petroleum products, including jet fuel, distillate, etc., in the last few years.

The Canadian oil industry is in the midst of consolidation, reducing the number of active companies. Companies operating in Canada include Exxon's

Imperial Oil, Royal Dutch/Shell's Shell Canada, Petro-Canada, and Suncor. Two of the largest companies, Alberta Energy and PanCanadian, began merger discussions in January 2002. If the deal goes through, the new company reportedly will become the largest independent North American producer.

Exploration and Production

Western Canada, and more specifically Alberta, remains the premier energy producing region in Canada. The Western Canadian Sedimentary Basin, underlying Alberta, Saskatchewan, and part of the Northwest Territories, has been the main source of Canadian oil production for the last 50 years. An estimated 55% of Canada's conventional oil production in 2000 came from Alberta. Conventional oil production has been declining in the west as it has been rising in the east in the last few years. However, as east coast projects are more expensive and develop smaller reserves, focus is expected to shift back toward the western part of the country in coming years.

Exploration and production activity on Canada's east coast is focused on the Jeanne d'Arc Basin, offshore Newfoundland. The climate demands technologically advanced offshore oil platforms, able to withstand extremely cold temperatures and high winds, which add to production costs. The first project in the area, the Hibernia field, came onstream in 1997 and produces around 150,000 bbl/d of light, sweet crude. Hibernia was subject to repeated delays, and grants totaling about $625 million from the federal government helped the project progress. ExxonMobil is the operator, with joint venture partners Chevron Canada Resources, PetroCanada, Canada Hibernia Holding Corporation, Murphy Oil, and Norsk Hydro.

The second project in the Jeanne d'Arc Basin, Terra Nova, began production in January 2002 after several delays. Terra Nova is about 30 miles away from the Hibernia field. The field currently has a capacity of 110,000 bbl/d and is expected to produce for about 15 years. Terra Nova is owned by PetroCanada (operator), ExxonMobil, Husky Oil Operations, Norsk Hydro, Murphy Oil Company, Mosbacher Operating, and Chevron Canada Resources.

There are two more Jeanne d'Arc fields, White Rose and Hebron. The White Rose field is expected to be the third Grand Banks development, beginning production in 2004, although concerns remain that development will be prohibitively expensive. The field could reach a projected 90,000 bbl/d at peak production. Finally, Chevron Canada Resources decided in February 2002 to defer development at the Hebron field, for financial reasons. Hebron contains heavier oil than Hibernia and Terra Nova.

On the west coast, a provincial British Columbia agency plans to review a 30-year-old ban on exploration in the Pacific Ocean. The area near Queen Charlotte Island is thought to hold as much as 10 billion barrels of oil as well as significant reserves of natural gas. This has the potential to make the area a larger oil and gas producer than the Jeanne d'Arc Basin.

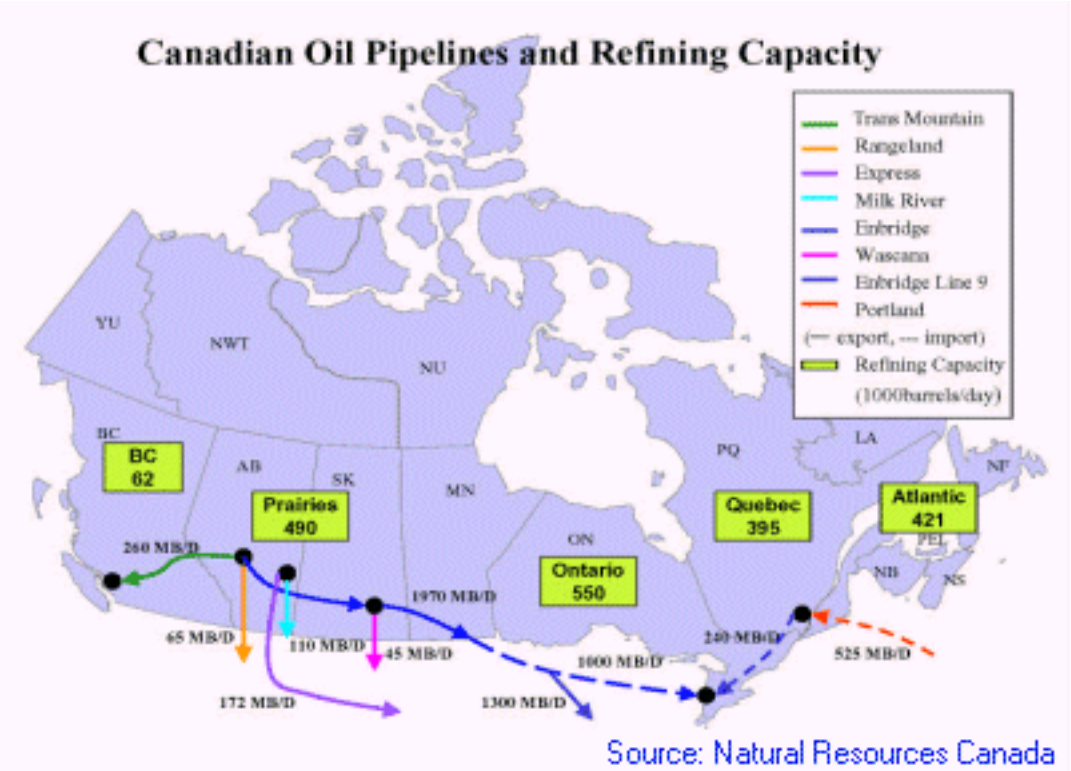
Synthetic Crude Oil

Much of the exploration in Alberta in coming years likely will be for heavy crude and oil sands, as conventional oil reserves are being depleted. Unlike conventional oil, oil sands are a mixture of bitumen, sand, water and clay. The bitumen, a thick and tar-like hydrocarbon, surrounds the sand and water. To develop oil sands, bitumen is separated from the sand, water and clay. Once separated, bitumen can be upgraded into a high-quality oil called "synthetic crude." One of the largest synthetic crude producers, Syncrude (a joint venture of Alberta Energy, Canadian Oil Sands Investments Inc., Conoco, Imperial, Mocal Energy, Murphy Oil, Nexen, and Petro-Canada), reported an average production cost of about $11.50/bbl in 2001.

Canada holds around 2 trillion barrels of oil sands. The Athabasca Oil Sands deposit, in northern Alberta, is one of the two largest oil sands deposits in the world (the other is in the Orinoco Belt, Venezuela). There are also oil sands deposits on Melville Island, in the Canadian Arctic, and there are three smaller deposits in northern Alberta.

Current output of synthetic crude and bitumen is estimated at 600,000 bbl/d.

According to the Canadian government, synthetic oil and bitumen production is expected to reach 1.2 million bbl/d by 2010.



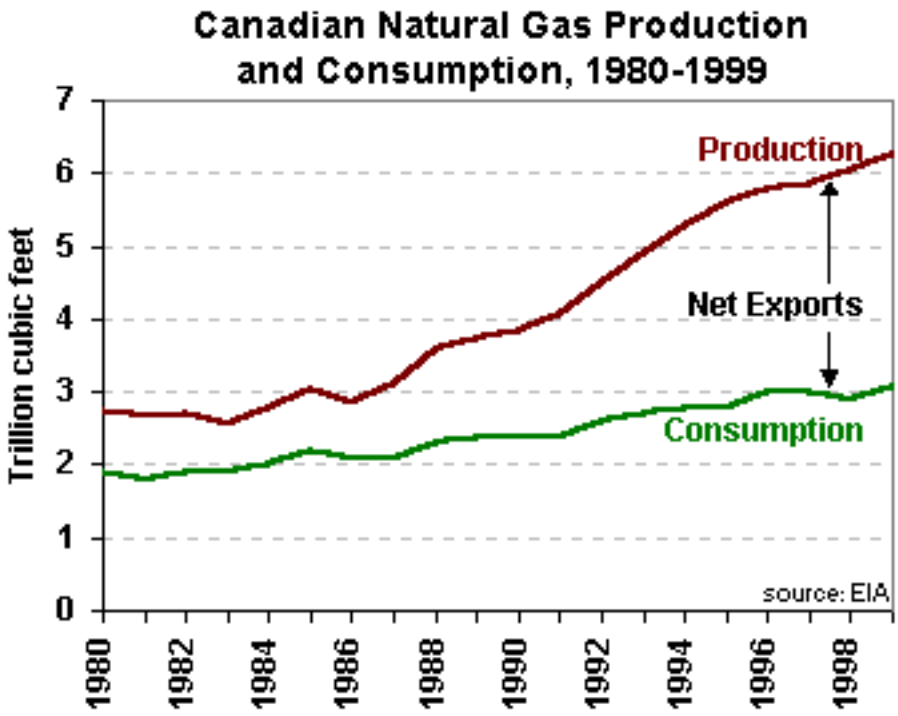
Pipelines

Although most Canadian oil is produced in western Canada (Alberta), oil is consumed primarily in central and eastern Canada. As a result, Canada exports oil from Alberta and imports oil on the east coast, explaining why Canada exports over 1 million bbl/d (gross) to the United States but has net exports of less than 1 million bbl/d. Furthermore, there is an extensive pipeline system to transport western oil to eastern Canadian and U.S. markets. There are two major pipeline networks. The first is Enbridge Pipelines Inc. (formerly Interprovincial Pipe Line-IPL), an 8,700-mile network of piping and terminals, delivering oil from Edmonton, Alberta, east to Montreal, Quebec and eastern Canada and the U.S. Great Lakes refineries and markets. It is one of the largest crude oil and petroleum liquids pipeline systems in the Western Hemisphere, and there are plans to expand its U.S. export capacity. The other major pipeline system is the Trans Mountain Pipe Line (TMPL), which delivers oil mainly from Alberta west to refineries and terminals in the Vancouver, British Columbia area, as well as to the Puget Sound area of Washington state.

BC Gas announced in January 2002 that it intends to build a new pipeline to transport bitumen from mines and and refineries near Fort McMurray to pipelines and processing plants in the Edmonton area. The proposed pipeline

would cover about 320 miles and cost about $625 million. BC Gas predicts that if regulatory approval is granted in early 2003, the pipeline could come onstream by 2005.

NATURAL GAS



Canada holds about 59.7 trillion cubic feet (Tcf) of proven natural gas reserves. Canada currently produces about 6.3 Tcf of natural gas per year, making it the world's third largest natural gas producer (after the United States and Russia) and second largest natural gas exporter (after Russia). Canada's natural gas exports go almost exclusively to the United States. Canadian natural gas consumption is projected to grow significantly in coming decades, largely for use in electricity generation. As natural gas production and infrastructure grow, there is a potential for emergence of a unified North American natural gas market.

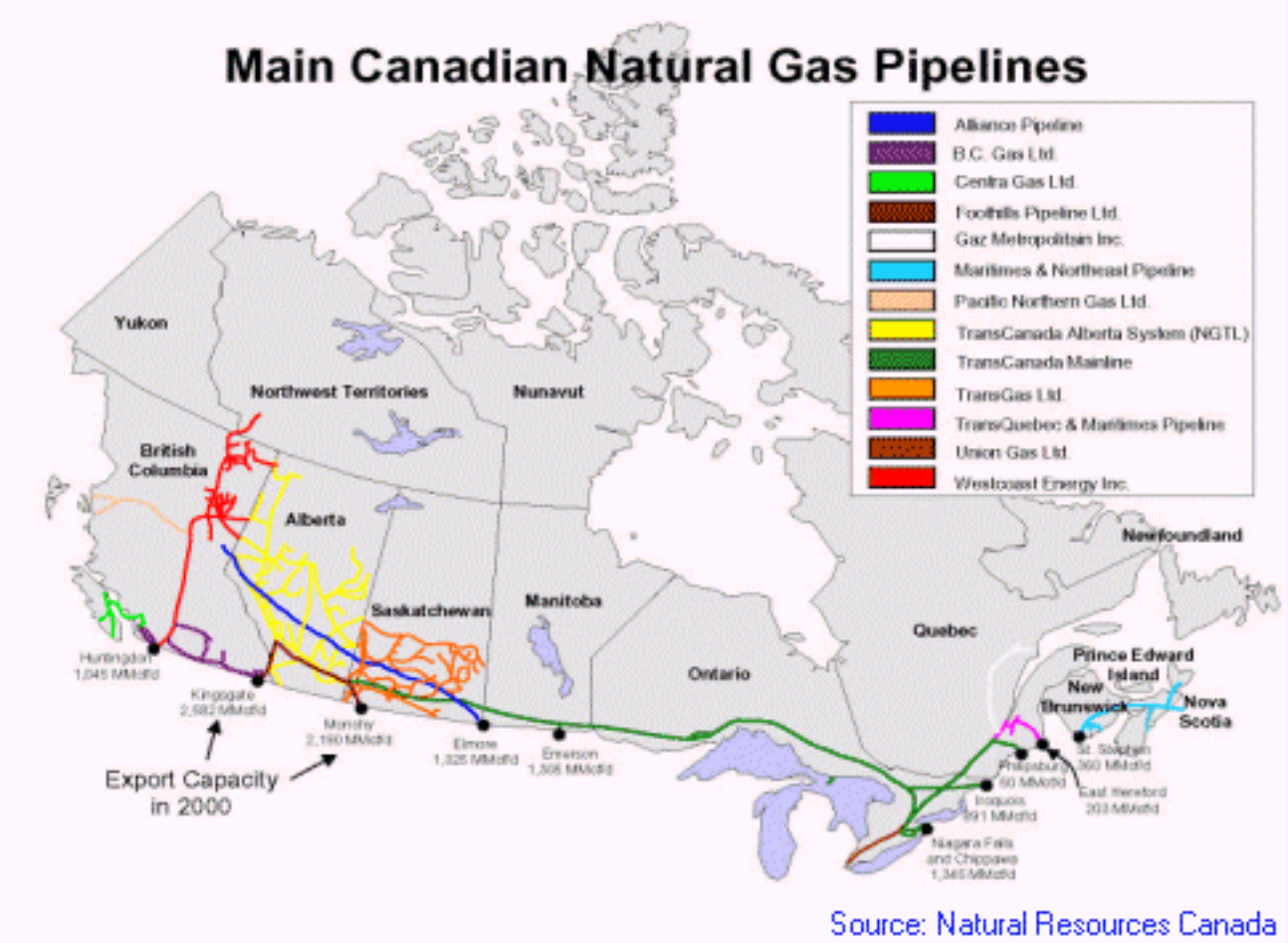
Exploration and Production

Like the oil industry, Canada's natural gas industry is based primarily in Alberta, reaching into neighboring Saskatchewan, British Columbia, and the southern Northwest Territories. Saskatchewan is expected to become an increasingly important natural gas province in coming years. Atlantic Canada is a newer industry focal point. Nova Scotia's Sable Island and offshore Newfoundland hold significant natural gas reserves.

Sable Island Offshore Energy, a consortium led by Mobil Canada and including Shell Canada, Imperial Oil, Nova Scotia Resources and Mosbacher

Operating, began production in January 2000. About 550 million cubic feet per day of natural gas is pumped from three reservoirs at Sable Island's Thebaud platform. Shell had originally estimated Sable reserves to hold 1.1 Tcf, but in January 2002 that estimate was revised downwards to 0.8 Tcf.

The Arctic Northwest Territories and the Yukon are thought to hold great potential for new gas discoveries. While the territories are unlikely to exceed Alberta's production, as Alberta becomes increasingly mature the territories represent a major potential new source of gas. Calgary-based Berkley Petroleum, Chevron Canada, and Ranger Oil all have made discoveries in the Northwest Territories. The Mackenzie Delta area of the Northwest Territories reportedly could hold as much as 65 Tcf of natural gas.



Pipelines

There has been considerable progress in recent years on natural gas interconnections between Canada and the United States. The Northern Border

Pipeline, an extension of the Nova Pipeline, came onstream in late 1999 and connects to Chicago through the upper Midwest. The Maritimes and Northeast Pipeline came onstream in January 2000, running from Sable Island to New England, with further extensions into New England planned. In February 2002, Enbridge shelved plans to build a pipeline connection between Sable Island and Quebec.

The $2.5-billion Alliance Pipeline, at 1,875 miles, is the longest pipeline ever built in North America, and is designed to carry about 1.3 billion cubic feet per day (Bcf/d) of gas from western Canada (Fort St. John, British Columbia) to the Chicago area. The pipeline began commercial service on December 1, 2000. The U.S. utility Pacific Gas & Electric imports natural gas from British Columbia via the Alliance pipeline.

The Millennium Pipeline remains in the regulatory approval stage of development; it is slated to connect Canadian sources to southern New York and Pennsylvania. Indecision over the final route of the pipeline in New York currently is stalling progress.

Exploration and production activity in the Mackenzie Delta, Beaufort Sea, and Alaskan North Slope has sparked interest in an Arctic pipeline. Combined Alaskan and Canadian assets in the area stand at about 40 Tcf of proven reserves, with far more probable reserves. Alaskan, Yukon, and Northwest Territory governments all support different routes, with various companies vying for their chosen routes.

Low natural gas prices as of February 2002 appear to be having a negative effect on the prospects for Arctic pipeline development. BP, formerly one of the companies most publicly committed to an Alaska pipeline, now has stated that the pipeline is not a good project in the current price environment. However, in January 2002, the Mackenzie Delta Producers Group, led by Imperial Oil, announced that it is seeking regulatory approval the Mackenzie line, to connect to Alberta. TransCanada Pipelines and Enbridge, Canada's two largest pipeline companies, remain interested in building outlets for

northern gas.

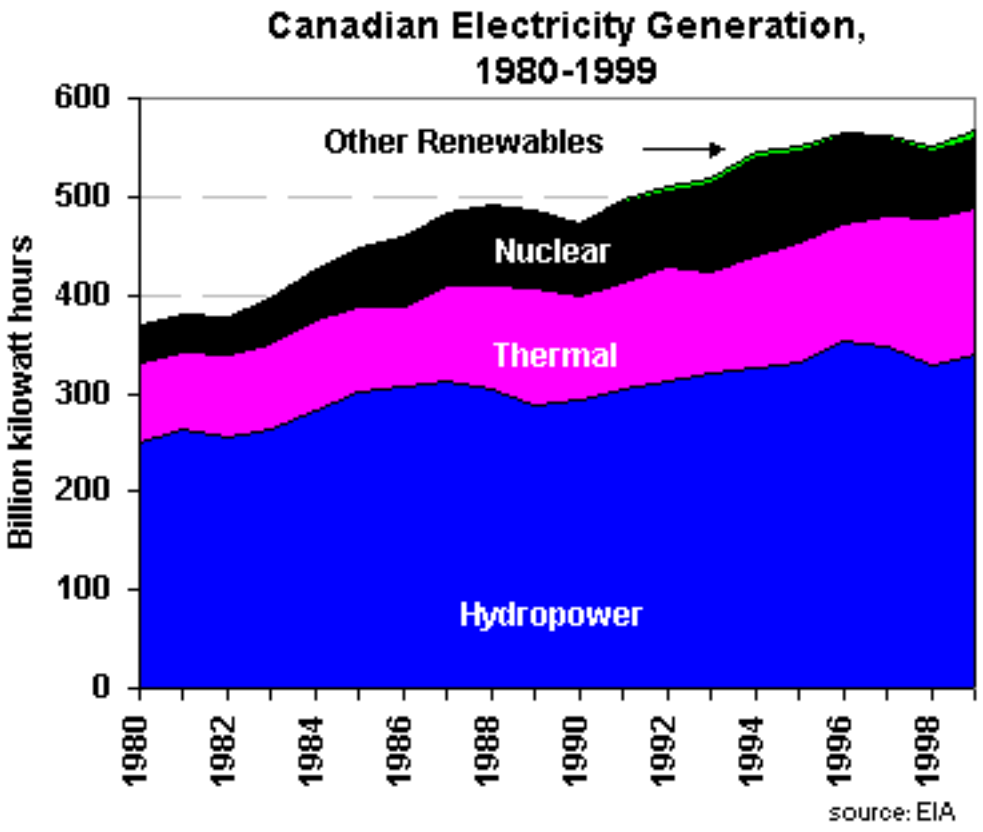
COAL

Canada is a major coal producer and consumer, with estimated 1999 output of 79.9 million short tons (Mmst), consumption of about 63.4 Mmst, and reserves of 9.5 billion short tons. About 80% of Canada's coal exports are for metallurgical purposes, with the vast majority purchased by Japan (60%) and South Korea (16%). Alberta accounts for about half of Canada's coal production, while British Columbia and Saskatchewan account for about 30% and 15%, respectively. Bituminous coal makes up about half of Canada's coal output, with sub-bituminous (about one-third) and lignite the rest. Canadian coal consumption is primarily (87%) for electricity generation, with the remainder mainly used for steel-making.

ELECTRICITY

Canadian electricity generation in 1999 totaled 567.2 billion kilowatt hours (bkwh), of which 60% was hydropower, 26% was conventional thermal power (oil, gas, and coal), 12% was nuclear generation, and 1% was derived from other renewable sources. Canada was the largest producer of hydropower in the world in 1999, and hydro sources are not yet believed to be fully exploited. Trends in coming years are expected to favor thermal power generation, mainly from natural gas. The Canadian nuclear power industry has declined to 69.8 bkwh in 1999 since its peak of 102.4 bkwh in 1994. Ontario contains the bulk of Canadian nuclear capacity.

Canada exported about 42.9 bkwh of electricity to the United States in 1999, mostly from Quebec, Ontario, and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Washington state, Minnesota, California, and Oregon. There is considerable reciprocity between the Canadian and U.S. power markets, as the United States also exports smaller volumes of electricity to Canada.



Natural gas-fired power plant construction is on the rise in Canada, preparing for a three-fold increase in gas power generation in the next decade, as predicted by the Canadian Energy Research Institute. PanCanadian Petroleum, TransAlta, EPCOR, and ATCO Power are all in various stages of developing new (mostly cogeneration) gas-fired plants in Alberta and Saskatchewan.

Under Canada's constitution, electricity is primarily within the jurisdiction of the provinces. In most provinces, the bulk of generation, transmission, and distribution is provided by a few dominant utilities. Although some of these utilities are privately owned, most are owned by the provinces. There is also limited independent power producer (IPP) generation, mostly for sales to the larger utilities.

Alberta and Ontario, which together account for about half of Canada's electricity market, have introduced legislation to deregulate their power sectors. Alberta is much further along in the deregulation process. It was the first province to introduce privatization legislation in 1995, and a 1998 amendment to the original legislation allowed retail customers to choose their electricity suppliers beginning January 1, 2001.

Ontario introduced privatization legislation in 1998, and deregulation is set to commence in the province in May 2002. Ontario's Hydro One utility, the

successor to the province's Crown monopoly Ontario Hydro, is slated for initial public offering (IPO) in 2002. It is expected to be Canada's largest-ever IPO.

Quebec and British Columbia do allow third party access to their electricity grids as the result of trade agreements with the United States, but neither province has plans to break up its utility monopoly.

ENVIRONMENT

Canada's energy abundance has encouraged the development of a highly fuel-intensive economy based on natural resource extraction and processing. This heavy reliance on energy-intensive industries has led to serious environmental concerns, primarily regarding air pollution and climate change.

In 1999, Canada consumed 12.5 quadrillion Btu of energy and emitted 150.9 million metric tons of carbon. The industrial sector was the primary emitter of carbon dioxide and within the sector, six energy intensive industries accounted for over 80% of these emissions. Per capita energy consumption ranks fourth among OECD countries, and per capita carbon emissions rank third.

Entering the 21st century, Canada is proving to be a leader in addressing environmental concerns. Renewable energy sources, such as wind, are beginning to gain more attention as Canada works toward meeting international obligations to reduce greenhouse gas emissions.

COUNTRY OVERVIEW

Prime Minister: Jean Chretien (since 11/4/93)
Independence: July 1, 1867 (from UK)
Population (July 2001E): 31.6 million
Location/Size: Northern North America/3.85 million sq. miles (slightly larger than the United States)
Administrative divisions: 10 provinces and 3 territories*; Alberta, British

Columbia, Manitoba, New Brunswick, Newfoundland, Northwest Territories*, Nova Scotia, Nunavut*, Ontario, Prince Edward Island, Quebec, Saskatchewan, Yukon Territory*
Major Cities: Toronto, Montreal, Vancouver, Ottawa (capital), Edmonton, Calgary, Winnipeg, Quebec
Languages: English (official), French (official)
Ethnic Groups: British Isles origin (40%), French origin (27%), other European (20%), indigenous Indian, Eskimo (1.5%)
Religions: Roman Catholic (45%), Protestant (41%)
Defense (8/98): Army (20,900), Navy (9,000), Air Force (14,000), Other (15,700)

ECONOMIC OVERVIEW

Exchange Rate (2/21/01): $1 U.S. = $1.61 Canadian dollars
Gross Domestic Product (GDP, 2000E, $U.S.): $691.8 billion
Real GDP Growth Rate (2001E): 1.4% **(2002F):** 1.1%
Inflation Rate (consumer prices, 2002E): 1.4%
Unemployment Rate (2002F): 7.6%
Current Account Balance (2002E, $U.S.): $13.5 billion
Major Export Products: Motor vehicles and parts, newsprint, wood pulp, timber, crude petroleum, machinery, natural gas, aluminum, telecommunications equipment, electricity
Major Import Products: Machinery and equipment, crude oil, chemicals, motor vehicles and parts, durable consumer goods, electricity
Major Trading Partners: United States, European Union

ENERGY OVERVIEW

Minister of Natural Resources: Herb Dhaliwal
Conventional Crude Oil Reserves (2002): 4.4 billion barrels
Oil Sands Reserves (002): 174.8 billion barrels
Oil Production (2001E): 2.8 million bbl/d, of which 2.0 million bbl/d was crude oil
Oil Exports to the United States (January-November 2001): 1.775 million bbl/d, 1.316 million bbl/d of which was crude oil

Oil Consumption (2001E): 2.0 million bbl/d
U.S. Oil Imports from Canada (January-November 2001E): 1.67 million bbl/d (of which 1.28 million bbl/d was crude)
Natural Gas Reserves (1/1/02): 59.7 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 6.3 Tcf
Natural Gas Consumption (1999E): 3.1 Tcf
Coal Reserves (12/31/96): 9.5 billion short tons
Coal Production (1999E): 79.9 million short tons (Mmst)
Coal Consumption (1999E): 63.4 Mmst
Electric Generation Capacity (1/1/99): 109.8 million kilowatts
Electricity Generation (1999E): 567.2 billion kilowatt hours (60% hydro, 26% thermal, 12% nuclear, 1% geothermal and other)

ENVIRONMENTAL OVERVIEW

Minister of Environment: David Anderson
Total Energy Consumption (1999E): 12.5 quadrillion Btu* (3.3% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 150.9 million metric tons of carbon (2.5% of world carbon emissions)
Per Capita Energy Consumption (1999E): 410.7 million Btu (vs U.S. value of 355.9 million Btu)
Per Capita Carbon Emissions (1999E): 4.9 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (1999E): 17,401 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 0.21 metric tons of carbon/thousand $1990 (vs U.S. value of 0.20 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (48.0%), Residential (17.7%), Transportation (18.9%), Commercial (15.5%)
Sectoral Share of Carbon Emissions (1998E): Industrial (40.3%), Transportation (33.0%), Residential (14.0%), Commercial (12.7%)
Fuel Share of Energy Consumption (1999E): Oil (30.4%), Natural Gas (25.3%), Coal (11.6%)
Fuel Share of Carbon Emissions (1999E): Oil (44.9%), Natural Gas

(31.0%), Coal (24.1%)
Renewable Energy Consumption (1998E): 3,850 trillion Btu*
Number of People per Motor Vehicle (1998): 1.8 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 4th, 1992). Under the negotiated Kyoto Protocol (signed on April 29th, 1998, but not yet ratified), Canada has agreed to reduce greenhouse gases 6% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Air pollution and resulting acid rain severely affecting lakes and damaging forests; metal smelting, coal-burning utilities, and vehicle emissions impacting on agricultural and forest productivity; ocean waters becoming contaminated due to agricultural, industrial, mining, and forestry activities
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Law of the Sea and Marine Life Conservation

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999.

OIL and GAS INDUSTRIES
Organization: private sector (major companies: ExxonMobil's Imperial Oil,

Royal Dutch/Shell's Shell Canada, Petro-Canada, Suncor, PanCanadian, Alberta Energy).
Major Oil and Gas Producing Provinces: Alberta; British Columbia; Saskatchewan
Major Oil Pipelines: Trans Mountain; Enbridge
Oil Refining Capacity, January 2002: Ontario (560,200 bbl/d); Alberta (435,550 bbl/d); Quebec (394,900 bbl/d); New Brunswick (250,000 bbl/d); British Columbia (62,250 bbl/d); Newfoundland (105,000 bbl/d); Nova Scotia (84,000 bbl/d); Sas katchewan (52,000 bbl/d)
Major Gas Pipeline Companies: Enbridge, TransCanada PipeLines Ltd.

Sources for this report include: CIA World Factbook; Dow Jones; DRI/WEFA World Economic Outlook; Economist Intelligence Unit ViewsWire; Financial Times; Oil and Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; U.S. Energy Information Administration; World Markets Online.

LINKS

For more information from EIA on Canada, please see:
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Links to other U.S. Government sites:
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Canadian Energy Pipeline Association
Sable Island
Hibernia
Alliance Pipeline
Millennium Pipeline
Maritimes and Northwest Pipeline
Northern Border Pipeline
The Coal Association of Canada

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June 2002

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China

The People's Republic of China (China) is the world's most populous country and the second largest energy consumer (after the United States). Production and consumption of coal, its dominant fuel, is the highest in the world. Rising oil demand and imports have made China a significant factor in world oil markets. All information contained in this report is the best available as of May 2002 and is subject to change.

GENERAL BACKGROUND

China is the world's most populous country, with a rapidly growing economy.

Economic development has proceeded unevenly, with urban coastal areas, particularly in the Southeast, experiencing more rapid economic development than other areas of the country. China has a mixed economy, with a combination of state-owned and private firms. A number of state-owned firms have undergone partial or full privatization in recent years. The Chinese government has encouraged foreign investment -- in some sectors of the economy and subject to constraints -- since the 1980s, offering several "special economic zones" in which foreign investors receive preferable tax, tariff, and investment treatment.

With China's entry into the World Trade Organization (WTO) in November 2001, the Chinese government made a number of specific commitments to trade and investment liberalization which, if fully implemented, will substantially open the Chinese economy to foreign firms. In the energy sector, this will mean the lifting or sharp reduction of tarriffs associated with imports of some classes of capital goods, and the eventual opening to foreign competition of some areas such as retail sales of petroleum products. It still remains to be seen how these commitments will be implemented.

Despite moves toward privatization, much of China's economy remains controlled by large State Owned Enterprises (SOE's), many of which are inefficient and unprofitable. Restructuring of the SOE sector, including the privatization of some enterprises, is a major priority of the government, as is restructuring of the banking sector. Many Chinese banks have had to write off large amounts of delinquent debts from state-owned enterprises. Quarterly earnings at many SOEs are reported to have fallen sharply in the first quarter of 2002, after rising in 2001. It is unclear how much of this is due to changes in accounting practices, as opposed to other factors such as weak demand for exports.

Layoffs have been part of the restructuring of the SOEs, as many were severely overstaffed. This has created unemployment, and also has been a burden on the government budget, as the government begins to provide social benefits which were previously the responsibility of the SOEs. Large protests

against SOE layoffs have taken place in early 2002, including in cities closely associated with the oil and coal industries.

China's real GDP grew by 7.3% in 2001, according to official Chinese figures, down from 8.0% growth in 2000. Real GDP growth for 2002 is forecast at 7.0%. The Chinese government's current Five Year Plan (2001-2005) sets a target of 7.0% real annual GDP growth. Some outside analysts have questioned the reliability of the official data, however.

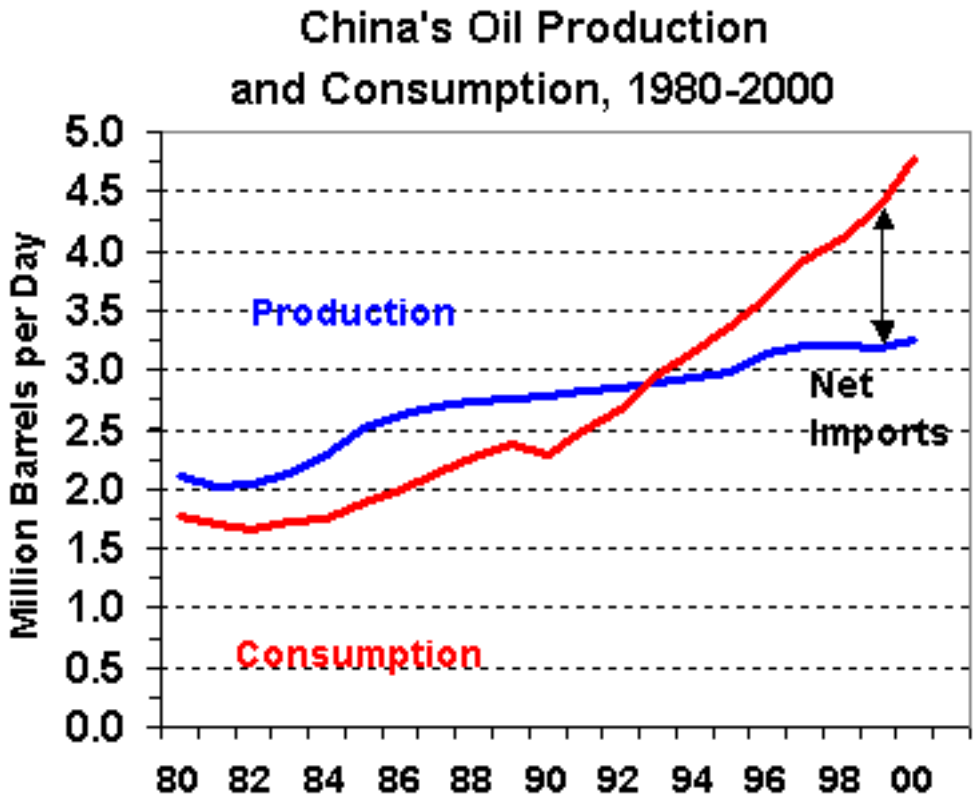
Inflows of Foreign Direct Investment (FDI) into China in 2001 totalled $46.8 billion, a new record, and data from the first two months of 2002 shows continuing strength. Japan, Taiwan, and the United States are China's most important sources of FDI.

In general, China's trade surplus has been falling in recent years, and imports have been rising. The 2001 trade surplus was $22.6 billion, down from a peak of $43.6 billion in 2001. Imports have been increasing, largely capital goods being acquired to refurbish outdated industrial facilities, but also consumer goods.

China has several territorial disputes with other regional states which are relevant to the energy sector, particularly the dispute over the potentially hydrocarbon-rich Spratly Islands, which are claimed by China, Vietnam, the Phillipines, Brunei, Taiwan, and Malaysia. Another dispute is over the East China Sea, claimed by Japan.

OIL

China currently is the world's third largest oil consumer, behind the United States and Japan. Consumption of petroleum products totalled 4.78 million barrels per day (bbl/d) in 2000, up from 4.36 million bbl/d in 1999. China is expected to surpass Japan as the second largest world oil consumer within the next decade and reach a consumption level of 10.5 million bbl/d by 2020, making it a major factor in the world oil market.



Note: Production includes crude oil, natural gas liquids and refinery gain.

China's petroleum industry has undergone major changes in recent years. In 1998, the Chinese government reorganized most state owned oil and gas assets into two vertically integrated firms -- the China National Petroleum Corporation (CNPC) and the China Petrochemical Corporation (Sinopec). Before the restructuring, CNPC had been engaged mainly in oil and gas exploration and production, while Sinopec had been engaged in refining and distribution. In 1998, the Chinese government ordered an asset swap which transferred some exploration and production assets to Sinopec and some refining and distribution assets to CNPC. This created two regionally focused firms, CNPC in the north and west, and Sinopec in the south, though CNPC is still tilted toward crude oil production and Sinopec toward refining. Other major state sector firms in China include the China National Offshore Oil Corporation (CNOOC), which handles offshore exploration and production and accounts for more than 10% of China's domestic crude production, and China National Star Petroleum, a new company which was created in 1997.

The intention of the restructuring was to make these state firms more like similar vertically integrated corporate entities elsewhere. In connection with this process, the firms have been spinning off or eliminating many unprofitable ancillary activities such as running housing units, hospitals, and other services near company facilities. Massive layoffs also have been undertaken, as like many other Chinese SOEs, they were severely overstaffed.

Labor unrest has been reported in early 2002 in several locations with CNPC facilties.

The three largest Chinese oil and gas firms - Sinopec, CNPC, and CNOOC - all have successfully carried out initial public offerings (IPOs) of stock within the last two years, bringing in billions of dollars in foreign capital. CNPC separated out most of its high quality assets into a subsidiary called PetroChina in early 2000, and carried out its IPO of a minority interest on both the Hong Kong and New York stock exchanges in April 2000. The IPO raised over $3 billion, with BP the largest purchaser at 20% of the shares offered. Sinopec carried out its IPO in New York and Hong Kong in October 2000, raising about $3.5 billion. Like the PetroChina IPO, only a minority stake of 15% was offered. About $2 billion of this amount was purchased by the three global super-majors - ExxonMobil, BP, and Shell. CNOOC held its IPO of a 27.5% stake in February 2001, after an earlier attempt in September 1999 was canceled. Shell bought a large block of shares valued at around $200 million.

Several aspects of these stock offerings were very atypical. First, they all involved only minority stakes. Second, they have not given the foreign investors a major voice in corporate governace. The Chinese government still holds majority stakes in all three firms, and the foreign investors have not received seats on their boards of directors. Analysts have generally seen these investments as attempts by the supermajors to gain a foothold in China, which will necessarily involve partnerships with the Chinese majors. Even with the opening to foreign investment envisioned in China's commitments for membership in the WTO, it is still likely that almost all major oil and gas projects in China will involve one of the Chinese majors. The Chinese government stipulated in July 2001 that only CNPC and Sinopec will be allowed to open new retail filling stations prior to fulfillment of China's market-opening commitment in 2004. This is seen as an attempt to strengthen their control of retail sales of petroleum products and ensure that foreign firms will have to partner with one or the other of the Chinese majors to enter the retail market, even after 2004. All three of the global supermajors, BP,

ExxonMobil, and Shell, are planning to enter the Chinese retail market in partnership with CNPC, Sinopec, or both.

As a net oil importer since 1993, China's petroleum industry is focused on meeting domestic demand, but it does still export a modest amount of crude oil. The largest export customer by far is Japan, which imports Daqing crude oil to burn directly in electric power plants. As of early 2002, China's exports of Daqing crude oil to Japan were around 50,000 bbl/d, down substantially from export levels during the 1990s.

Most Chinese oil production capacity, close to 90%, is located onshore. One field alone, Daqing in northeastern China, accounts for about 1.0 million bbl/d of China's production, out of a total crude oil production of around 3.3 million bbl/d. Daqing is a mature field, however, having begun production in 1963. It is expected to show declining production in the future, but the discovery of additional small oil-bearing structures at the field and the introduction of enhanced recovery technologies may slow the decline. At China's second-largest producing field, Liaohe in northeastern China, CNPC has solicited proposals from potential foreign partners to help it enhance recovery rates and extend production, though no contracts have yet been signed. In December 2000, regulatory changes were announced which will remove some of the barriers to foreign firms forming partnerships with Chinese oil majors. Government priorities focus on stabilizing production in the eastern regions of the country at current levels, increasing production in new fields in the West, and developing the infrastructure required to deliver western oil and gas to consumers in the East. Offshore development also is a high priority. Chinese officials have said that they expect production in Xinjiang to reach 1 million bbl/d by 2008, but that seems ambitious, given that transportation of that oil to consumers in the East remains a major obstacle.

Recent offshore oil exploration interest has centered on the Bohai Sea area, east of Tianjin, believed to hold more than 1.5 billion barrels in reserves, and the Pearl River Mouth area. Phillips Petroleum announced in March 2000 that it had completed its appraisal drilling of the Peng Lai find in Block 11/05,

and would proceed with development. Full scale production at the field is expected to reach more than 100,000 bbl/d by 2004. Shell and CNOOC signed a production sharing contract for exploration in the Bonan area of the Bohai Sea in January 2001. Seismic survey work is taking place, and drilling is scheduled to begin in 2003. CNOOC also signed a production sharing contract with Canadian independent Husky Oil in July 2001 for Block 39-05 in the Pearl River Mouth, near the Wenchang 13-1/13-2 blocks, where Husky Oil and CNOOC already are producing about 50,000 bbl/d. Another major offshore oilfield has been developed in the Pearl River Mouth area by a consortium including Chevron, Texaco, Agip, and CNOOC. The field began production in February 1999. Meanwhile, improvement in Sino-Vietnamese relations has opened the way for oil and gas exploration in the Beibu Gulf (known in Vietnam as the Gulf of Tonkin). China and Vietnam signed an agreement in December 2000 which settled their outstanding disputes over sovereignty and economic rights in offshore areas near their border. The Spratly Islands in the South China Sea also are suspected to hold oil and gas reserves, but the area, as mentioned above, is claimed by several neighboring states.

With China's expectation of growing future dependence on oil imports, China has been acquiring interests in exploration and production abroad. CNPC holds oil concessions in Kazakhstan, Venezuela, Sudan, Iraq, Iran, and Peru, and Azerbaijan. Sinopec also has begun seeking to purchase overseas upstream assets. The most significant deal thus far is CNPC's aquisition of a 60% stake in the Kazakh oil firm Aktobemunaigaz, which came with a pledge to invest significantly in the company's future development over the next twenty years. While there had been some discussion of a possible oil pipeline from Kazakhstan to China, CNPC has said that it would only be considered if reserves were sufficient and it was economical, which looks doubtful. The Greater Nile Petroleum Operating Company (GNPOC), the Sudanese oil project in which CNPC owns a stake, began exports in August 1999. The CNPC concession in Iraq cannot be developed until United Nations economic sanctions are lifted, at least to the extent of allowing foreign investment in

Iraqi oil infrastructure. CNOOC also has purchased an upsteam equity stake in the small Malacca Strait oilfield in Indonesia.

Russia's Far East is seen as a potential source of Chinese crude oil imports. The Russian and Chinese governments have been holding regular discussions on the feasibility of pipelines to make such exports possible. One proposed major project is a $1.7-billion pipeline from Irkutsk to Beijing being backed by Russia's Yukos Oil, which, if developed, could carry 400,000 bbl/d of oil, mainly from the Tomsk region. CNPC and Yukos signed an agreement in July 2001 to carry out a feasibility study for the project, which is due to be completed in mid-2002. An alternative plan, proposed by Russian pipeline operator Transneft, would take Russian crude from both West Siberia and East Siberia via a 1 million bbl/d pipeline to an export terminal at the Pacific coast port of Nakhodka. China would presumably be one of the major consumers of oil from such a project, but it would also give Russia increased access to the Japanese, South Korean, and other East Asian markets.

Downstream infrastructure development in China centers primarily on upgrading existing refineries rather than building new ones, due to current overcapacity. In the late 1990s, the Chinese government shut down 110 small refineries, which generally made inferior quality petroleum products. 62 other small refineries owned by provincial and local governments also are likely to be merged into CNPC and Sinopec in the near future. Another major issue in the Chinese downstream sector is the lack of adequate refining capacity suitable for heavier Middle Eastern crude oil, which will become a necessity as Chinese import demand rises in the mid-term future. Several existing refineries are being upgraded to handle heavier and more sour grades of crude oil.

Chinese officials have spoken of their intention to build a national strategic petroleum reserve, but no formal policy announcement has taken place, and it is unclear whether China would build a government-held reserve of crude oil like the U.S. Strategic Petroleum Reserve (SPR) or make the maintenance of a minimum stock level a regulatory requirement of doing business as a refiner,

which is the basis for strategic reserves in Japan and South Korea.

NATURAL GAS

Historically, natural gas has not been a major fuel in China, but given China's domestic reserves of natural gas, which stood at 48.3 trillion cubic feet (Tcf) at the beginning of 2002, and the environmental benefits of using gas, China has embarked on a major expansion of its gas infrastructure. Until the 1990s, natural gas was used largely as a feedstock for fertilizer plants, with little use for electricity generation. Gas currently accounts for only slightly more than 3% of total energy consumption in China, but consumption is expected to more than triple by 2010. This will involve increases in domestic production, and imports, by pipeline and in the form of liquefied natural gas (LNG).

The country's largest reserves of natural gas are located in western and north-central China, necessitating a significant further investment in pipeline infrastructure to carry it to eastern cities. China is planning to build a pipeline, the "West-to-East Pipeline," from gas deposits in the western Xinjiang province to Shanghai, picking up additional gas in the Ordos Basin along the way. Shell was chosen in February 2002 as the lead firm for the project, and Gazprom and ExxonMobil will hold significant stakes. Sinopec also is likely to be added as an equity partner, but only for a 5% stake. Though construction had been scheduled to begin in 2001, it is unclear how long it will take to finalize terms for the contract. Some of the potential foreign partners in the project are reported to have concerns about the $18 billion project's commercial viability, even though letters of intent have been signed with several of the project's intended customers. The concern stems from the possibility that the Tarim Basin gas deposits may provide enough gas for only 20 years of operation, while close to 40 years of operation could be needed to make it profitable, given the massive construction costs. While it is unlikely to happen in the near future, the West-to-East Pipeline eventually could serve as a trunkline which could be extended to receive gas from Central Asia.

China announced a discovery of a major gas field at Sulige in the Ordos Basin in the Inner Mongolia Autonomous Region, adjacent to the Changqing

oilfield, in 2001. While the field is still under evaluation, recent unofficial reserve estimates cited in the trade press put reserves in the range of 16-21 Tcf, substantially more than was assumed when the discovery was first announced. Some natural gas from from the Ordos Basin is likely to be put into the West-to-East Pipeline, which was to run through the area in any case, and help make it economically viable. A pipeline was completed in 1997 between the Ordos Basin and Beijing, and a second pipeline is planned in the near future, as demand for natural gas in Beijing, Tianjin, and nearby Hebei province already is outstripping the capacity of the original pipeline.

Another proposed pipeline project would link the Russian natural gas grid in Siberia to China and possibly South Korea via a pipeline from the Kovykta gas fields near Irkutsk, which hold reserves of more than 50 Tcf. The cost of the project has been estimated at $12 billion, and a feasibility study is underway. The pipeline would have a planned capacity of 2.9 billion cubic feet per day (Bcf/d), of which China would likely consume about 1.9 Bcf/d and South Korea 1 Bcf/d. The main South Korea gas company, Kogas, formally joined the feasibility study in November 2000. The main foreign backer of the project is BP, which owns a 30% stake in Rusia Petroleum , the license holder for the Kovykta gas field. The project faces some hurdles, however, as it would involve South Korea becoming dependent on gas supplies routed through China and North Korea. The project seems to have made little progress in the last year, due to tensions on the Korean peninsula and possibly Chinese expectations of additional domestic supplies for northeastern China based on the large new natural gas find in the Ordos Basin. It is not clear that the project would be economical if it is not extended to South Korea.

Aside from these huge projects, other pipelines are being developed to link smaller natural gas deposits to other consumers. A pipeline was completed in early 2002 linking the Sebei natural gas field in the Qaidam Basin with consumers in the city of Lanzhou. Another planned project would link gas deposits in Sichuan province in the southwest to consumers in Hubei and Hunan provinces in central China at an estimate cost of $600 million.

One major hurdle for natural gas projects in China is the lack of a unified regulatory system. Currently, natural gas prices are governed by a patchwork of local regulations. The Chinese government is in the process of drafting a new legal framework for the natural gas sector, which has become an urgent priority to reassure Shell and other potential foreign investors in the West-to-East Pipeline that there will be a stable regulatory environment.

Offshore gas projects also are becoming a significant part of China's gas supply. The Yacheng 13-1 field, developed in the mid-1990s, has been producing gas for Hong Kong and Hainan Island since 1996. The Chunxiao gas field in the East China Sea, being developed by China National Star Petroleum, is also expected to become a significant producer within the next decade. The company puts the field's reserves at more than 1.6 Tcf. Another area where where exploratory drilling is planned is the Xihu Trough, in the East China Sea about 250 miles east of Shanghai.

Imported liquefied natural gas (LNG) will be used primarily in China's southeastern coastal region. Guangdong province already has launched a project to build six, 320-megawatt (MW) gas-fired power plants, and to convert existing oil fired plants with a capacity of 1.8 gigawatts (GW) to LNG. In March 2001, it was announced that BP had been selected to build China's first LNG import terminal, to be located near the city of Guangdong. BP will take a 30% equity stake in the project, with CNOOC holding 31% and the rest held by local firms from Guangdong and Hong Kong. Proposals for supplies of LNG to the terminal were received in May 2002 from three potential suppliers, RasGas of Qatar, Shell's Northwest Shelf LNG project in Australia, and BP's planned Tangguh LNG project in Indonesia. A second LNG import terminal is planned for Fujian province, to be completed in 2005 or 2006.

COAL

Coal makes up the bulk, over 63%, of China's primary energy consumption, and China is both the largest consumer and producer of coal in the world.

China's coal consumption in 2000 was 1.27 billion short tons, or over 24% of the world total. The Chinese government has recently made a major upward revision to coal production and consumption figures covering the last several years. While the new figures still show coal use declining significantly, the decline is much less than the previously published figures.

China's coal industry has had a serious oversupply problem in recent years, particularly in the late 1990s, and the government has begun implementing major reforms aimed at reducing the oversupply, returning large state-owned mines to profitability as a prelude to possible future privatization, and reducing mine accidents. Large state-owned coal mines had experienced buildups of unused inventories in the mid-to-late-1990s, and many were operating at a financial loss. A large number of small, unlicensed mines also have added to the oversupply. In 1998, the government launched a large-scale effort to close down the small mines. Many small coal mines have been closed, and the effort is continuing. As a result of the closures, depressed local coal prices have started to recover, and combined with cost-cutting measures, some of the large-scale mines returned to profitability in 2000. It has become clear, however, through much anecdotal evidence, that not all of the "closed" mines have actually ceased operation, and the recent revision to the Chinese State Statistical Bureau's production and consumption figures appears to reflect this. China also is increasingly seeking export markets for its coal as a way of dealing with its surplus production. According to figures published by the Chinese government, China's net coal exports for 2001 rose by 46% from the previous year. Japan and South Korea are the primary markets, and China is beginning to emerge as a serious competitor to Australia for Japanese coal imports. India also has been importing modest quantities of Chinese coal.

Over the longer term, China's coal demand is projected to rise significantly , roughly doubling by the year 2020. While coal's share of overall Chinese energy consumption is projected to fall, coal consumption will still be increasing in absolute terms. Several projects exist for the development of coal-fired power plants co-located with large mines, so called "coal by wire"

projects. Other technological improvements also are being undertaken, including the first small-scale projects for coal gasification, and a coal slurry pipeline to transport coal to the port of Qingdao. Coalbed methane production also is being developed, with recent American investors in this effort including BP, Texaco, and Virgin Oil, which was awarded a concession for exploration in Ningxia province in January 2001. Texaco is the largest foreign investor in coalbed methane, with activities in several provinces. Coalbed methane production is expected to reach 0.4 billion Tcf by 2010.

In contrast to the past, China is becoming more open to foreign investment in the coal sector, particularly in modernization of existing large-scale mines and the development of new ones. The China National Coal Import and Export Corporation is the primary Chinese partner for foreign investors in the coal sector. Areas of interest in foreign invesment concentrate on new technologies only recently introduced in China or with environmental benefit, including coal liquefaction, coal bed methane production, and slurry pipeline transportation projects. Over the longer term, China plans to aggregate the large state coal mines into seven corporations by the end of 2005, in a process similar to the creation of CNPC and Sinopec out of state assets. Such firms might then seek to pursue foreign capital through international stock offerings.

China has expressed a strong interest in coal liquefaction technology, and would like see liquid fuels based on coal substitute for some of its petroleum demand for transportation. The first pilot coal liquefaction plant is planned to be operational in coal-rich Shanxi in late 2001. Shell also signed an agreement in December 2001 for a coal gasification project in Yueyang in Hunan province, which is to replace naphtha as a feedstock for a large fertilizer plant.

ELECTRICITY

As with coal, China's electric power industry experienced a serious oversupply problem in 1998-99, due largely to demand reductions from closures of inefficient state-owned industrial units, which were major

consumers of electricity. The Chinese government responded to the short-term oversupply in part by implementing a drive to close down small thermal power plants and by imposing a moratorium (with a few exceptions) on approval of new power plant construction, which ran through January 1, 2002, and there have not been a large number of new projects approved since then. Most of the small power plants closed were diesel or coal-fired plants which were opened by provincial or municipal governments as demand grew in the 1980's, and were relatively inefficient and polluting. Even with the moratorium on new construction approvals, many power plants have been coming online, due to the very large backlog of power generation projects approved prior to the moratorium. When the moratorium took effect, there was a total of 70 GW of new capacity under construction or with final approval, much of which is still under development.

The largest project under construction, by far, is the Three Gorges Dam, which, when fully completed in 2009, will include 26 separate 700-MW generators, for a total of 18.2 GW. Plans were announced in March 2002 to reorganize the Three Gorges project into the China Three Gorges Electric Power Corporation. The corporation is expected to seek capital through an equity offering open to foreign investors, similar to those already carried out by the major Chinese oil companies, in 2003.

Another large hydropower project involves a series of dams on the upper portion of the Yellow River. Shaanxi, Qinghai, and Gansu provinces have joined to create the Yellow River Hydroelectric Development Corporation, with plans for the eventual construction of 25 generating stations with a combined installed capacity of 15.8 GW. Seven of these stations are either under construction or currently in operation.

Most of the major developments taking place in the Chinese electricity sector in 2002 involve nuclear power. Several nuclear projects are under construction, with the involvement of Russian, French, and Canadian firms. The first generation unit of the Lingao nuclear power plant in Guangdong province began commercial operation in May 2002, with a capacity of 1-GW.

The second 1 GW generating unit is expected to begin operating in March 2003. An additional 600-MW generating unit at the Qinshan nuclear power plant in Zhejiang province began operation in February 2002, and another 600-MW unit at the same site is scheduled to begin delivering electricity in late 2002.

A major issue for China's electric power industry is the distribution of generation among power plants. China's stated intention eventually is to create a unified national power grid, and to have a modern power market in which plants sell power to the grid at market-determined rates. In the short term, though, traditional arrangements still hold sway, and state-owned power plants which have government connections tend to have a higher priority than independent private plants. Additionally, some private plants with "take-or-pay" contracts, which provide for guaranteed minimum sales amounts, have had trouble getting the provincial authorities running the local grids to honor those terms.

In the short term, oversupply and uncertainty are likely to reduce foreign investment in China's power sector. In the longer term, though, growth in electricity consumption is projected at 5.5% per year through 2020. The largest gainer in terms of fuel share in the future is expected to be natural gas, due largely to environmental concerns in China's rapidly industrializing coastal provinces. If a truly competitive market for electric power develops as planned, the Chinese market may once again become attractive to foreign investment. At present, foreign direct investment is allowed only in power generation, but loan financing has been obtained for some power transmission projects.

The Chinese government is in the early stages of formulating a fundamental long-term restructuring of their electric power sector, embodies in the National Power Industry Framework Reform Plan promulgated by the State Council in April 2002. As with many other countries reform programs, generating assets are to be largely separated from transmission and distribution. The State Power Corporation (SPC) will divest most of its

generating assets (though retaining about 20%), and then be split into regional transmission and distribution companies. Electricity prices will still be regulated, but there are likely to be major changes in tarriffs and the overall regulatory structure for electricity pricing. The process is at an early stage, and many of the details remain to be worked out.

ENVIRONMENT

China suffers from major energy-related environmental problems. According to a report by the World Health Organization (WHO), seven of the world's ten most polluted cities are in China. The country's heavy use of unwashed coal leads to large emissions of sulfur dioxide and particulate matter. China also is important to any effort to curb emissions of greenhouse gases, as it is projected to experience the largest absolute growth in carbon dioxide emissions between now and the year 2020.

China is a non-Annex I country under the United Nations Framework Convention on Climate Change, meaning that it has not agreed to binding targets for reduction of carbon dioxide emissions under the Kyoto Protocol. While the Chinese government is concerned with its environmental problems, it tends to be more concerned with local problems, such as particulate matter and sulfur dioxide emissions. Thus, it is undertaking efforts to lessen emissions of pollutants such as sulfur dioxide and nitrogen oxide, through improved pollution controls on power plants as well as policies designed to increase the share of natural gas in the country's fuel mix, particularly around major metropolitan areas.

COUNTRY OVERVIEW

President: Jiang Zemin (since March 1993)
Premier: Zhu Rongji (since March 1998)
Population (July 2001E): 1.3 billion
Location/Size: Eastern Asia/3.7 million square miles (9.6 million square kilometers, slightly smaller than the United States)
Major Cities: Beijing (capital), Shanghai, Tianjin, Guangzhou, Shenyang, Wuhan, Chengdu, Hong Kong

Languages: Mandarin (official), many local dialects
Ethnic Groups: Han Chinese (92%); Zhuang, Uygur, Hui, Yi, Tibetan, Miao, Manchu, Mongol, Buyi, Korean, others (8%)
Religion: Officially atheist; Daoism, Buddhism, Muslim (2-3%); Christian (1%)
Defense (8/98): Army (2.1 million), Navy (260,000), Air Force (470,000), reserves (1.2 million), People's Armed Police (1 million)

ECONOMIC OVERVIEW

Currency: Yuan
Exchange Rate (6/2/02): US$1 = 8.3 Yuan/Renminbi
Gross Domestic Product (2001E): $1.18 trillion **(2002F):** $1.27 trillion
Real GDP Growth Rate (2001E): 7.3% **(2002F):** 6.7%
Inflation Rate (2002F): 0.6%
Current Account Surplus (2002F): $20.3 billion
Major Trading Partners: Japan, United States, European Union, South Korea, Taiwan
Merchandise Exports (2002F): $303.6 billion
Merchandise Imports (2002F): $254.1 billion
Merchandise Trade Surplus (2002F): $33.1 billion
Major Export Products: Light industrial and textile products, mineral fuels, heavy manufactures, agricultural goods
Major Import Products: Machinery, steel, chemicals, miscellaneous manufactures, industrial materials, grain
Monetary Reserves (2002F, non-gold): $174.2 billion
External Debt (2002F): $164.1 billion

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 24 billion barrels
Oil Production (2001E): 3.3 million barrels per day (bbl/d)
Oil Consumption (2001E): 4.9 million bbl/d
Net Oil Imports (2001E): 1.6 million bbl/d
Crude Oil Refining Capacity (1/1/02E): 4.5 million bbl/d
Natural Gas Reserves (1/1/02E): 48.3 trillion cubic feet (Tcf)

Natural Gas Production (2000E): 0.96 Tcf
Natural Gas Consumption (2000E): 0.96 Tcf
Recoverable Coal Reserves (1/1/96E): 126.2 billion short tons
Coal Production (2000E): 1.27 billion short tons
Coal Consumption (2000E): 1.31 billion short tons
Electric Generation Capacity (1/1/00E): 294 GW (222 GW thermal; 70 GW hydro; 2 GW nuclear)
Electricity Generation (1999E): 1,308 billion kilowatthours (1,070 conventional thermal; 220 hydro; 16 nuclear)

Statistical note: All data reported here exclude Hong Kong, a former British colony which reverted to China on July 1, 1997.

ENVIRONMENTAL OVERVIEW

Minister of Land and Natural Resources: Yongkang Zhou
Minister of Water Resources: Shucheng Wang
Total Energy Consumption (2000E): 36.7 quadrillion Btu (9.2% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 775.0 million metric tons of carbon (12.0% of world carbon emissions)
Per Capita Energy Consumption (2000E): 28.8 million Btu (vs. U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 0.61 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 35,201 Btu/$1995 (vs. U.S. value of 10,918 Btu/$1995)**
Carbon Intensity (2000E): 0.74 metric tons of carbon/thousand $1995 (vs. U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (1998E): Residential (28.3%), Industrial (59.9%), Transportation (7.4%), Commercial (4.4%)
Sectoral Share of Carbon Emissions (1998E): Transportation (8.6%), Industrial (75.1%), Commercial (5.3%), Residential (10.9%)
Fuel Share of Energy Consumption (2000E): Oil (26.8%), Natural Gas (3.0%), Coal (63.6%)

Fuel Share of Carbon Emissions (2000E): Oil (22.0%), Natural Gas (2.1%), Coal (75.9%)
Renewable Energy Consumption (1998E): 10,895 trillion Btu* (2% increase from 1997)
Number of People per Motor Vehicle (1998): 125 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified January 5th, 1993). Signatory to the Kyoto Protocol (signed May 29th, 1998 - not yet ratified).
Major Environmental Issues: Air pollution (greenhouse gases, sulfur dioxide particulates) from the overwhelming use of high-sulfur coal as a fuel, producing acid rain which is damaging forests; water shortages experienced throughout the country, particularly in urban areas and in the north; future growth in water usage threatens to outpace supplies; water pollution from industrial effluents; much of the population does not have access to potable water; less than 10% of sewage receives treatment; deforestation; estimated loss of one-fifth of agricultural land since 1949 to soil erosion and economic development; desertification; trade in endangered species.
Major International Environmental Agreements: A party to the Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94 and Wetlands. Has signed but not ratified: Nuclear Test Ban.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY

Organization: *Coal* - China National Local Coal Mines Development Corp., China Northeast & NEI-Mongolia United Coal Co., numerous local state-owned mines and rural collectives; *Coal import/exports* - China Coal Import and Export Group; *Petroleum* - China National Petroleum Corp. (CNPC, PetroChina is its publicly traded subsidiary), China National Offshore Oil Corp. (CNOOC), China National Oil & Gas Exploration & Development Corp. (CNODC), China National Star Petroleum (Star); China National Petrochemical Corp. (SINOPEC); *Oil imports/exports* - China National Chemicals Import and Export Corporation (SINOCHEM), China United Petroleum Corporation (China Oil), China United Petrochemical Corp. (UNIPEC); *Electric power* - China State Power Corp., Huaneng Group, Inc., China National Power Industry Corp. (CNPIC), regional electric power corporations, China National Nuclear Industry Corp., China International Water and Electric Corp. (CWE).; *Energy Finance* - China National Energy Investment Corp.

Major Producing Oil Fields (2000 Production): Daqing (1.1 MMBD), Shengli (0.5 MMBD), Liaohe (0.3 MMBD)

Major Refineries (1/1/02 Capacity): Fushun (184,800 bbl/d), Maoming (170,700 bbl/d), Qilu (160,700 bbl/d), Gaoqiao (150,600 bbl/d), Dalian (142,600 bbl/d), Yanshan (190,800 bbl/d), Jinling (140,600 bbl/d); Zhenlai (160,700 bbl/d)

Sources for this report include: Asia Pulse; Coal Week International; Dow Jones Newswire; Economist Intelligence Unit; Financial Times; Oil and Gas Journal; Oil Daily; Petroleum Economist; Petroleum Intelligence Weekly; South China Morning Post; U.S. Commerce Department; International Trade Administration -- Country Commercial Guides; U.S. Energy Information Administration; DRI/WEFA Asia Economic Outlook; World Gas Intelligence.

LINKS

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Lawrence Berkeley National Laboratory (LBNL) - China Energy Group
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U.S. State Department Consular Information Sheet - China Programs
U.S. State Department - Country Commercial Guide - China
U.S. State Department Background Notes on China
U.S. Embassy, Beijing
U.S. Embassy, Beijing, Report on "The Controversy Over China's Reported Falling Energy Use - August 2001"
Library of Congress Country Study on China

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China National Offshore Oil Corporation (CNOOC)
China Today

Chinaonline.com
National Bureau of Asian Research
Tradeport Trade Directory, China
" China by the Numbers: How Reform Affected Chinese Economic Statistics ," paper by Prof. Thomas Rawski, University of Pittsburgh

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