January 2004

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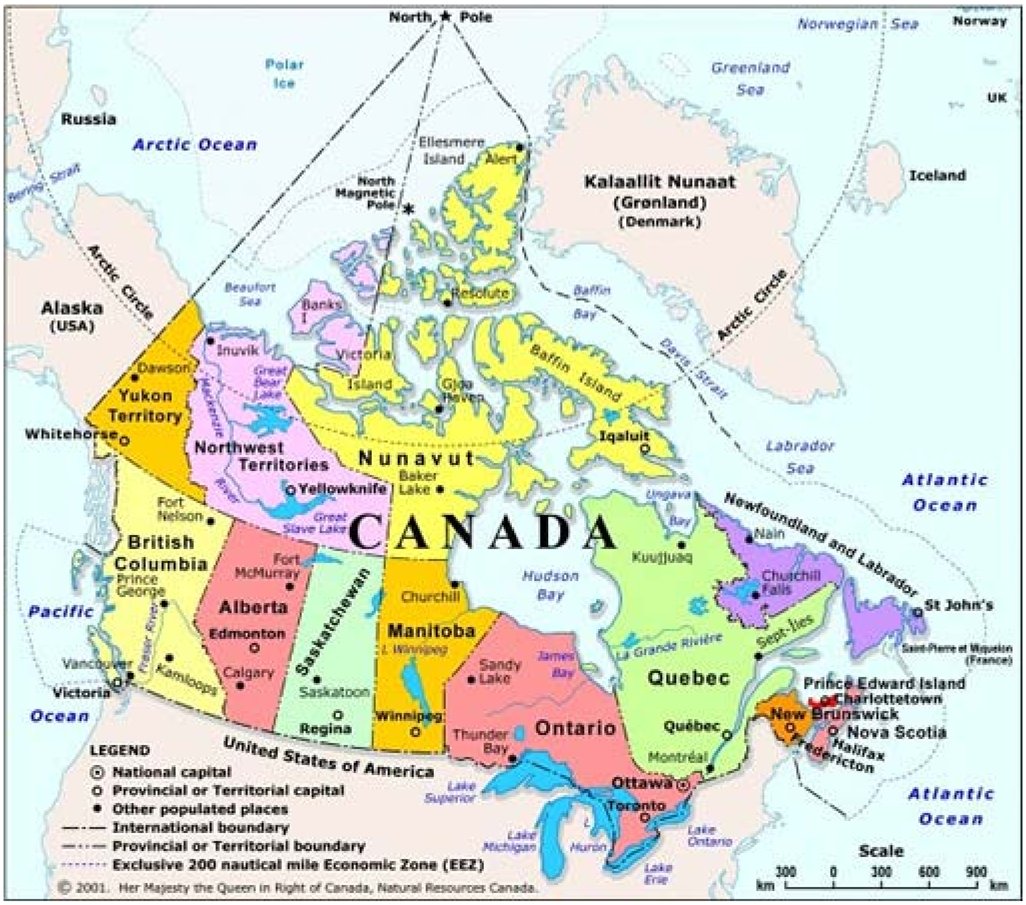
Canada

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 January 2004 and can change.



BACKGROUND

Canada is the United States' most important trading partner, with an equivalent of over $1 billion a day in goods, services, and investment crossing the borders in each direction in 2001. Canada and the U.S. also enjoy a highly interdependent energy relationship, trading oil, natural gas, and electricity. An example of this interdependence was an electric power outage on August 14, 2003, which left large portions of the Midwest and Northeast United States and Ontario, Canada without power.

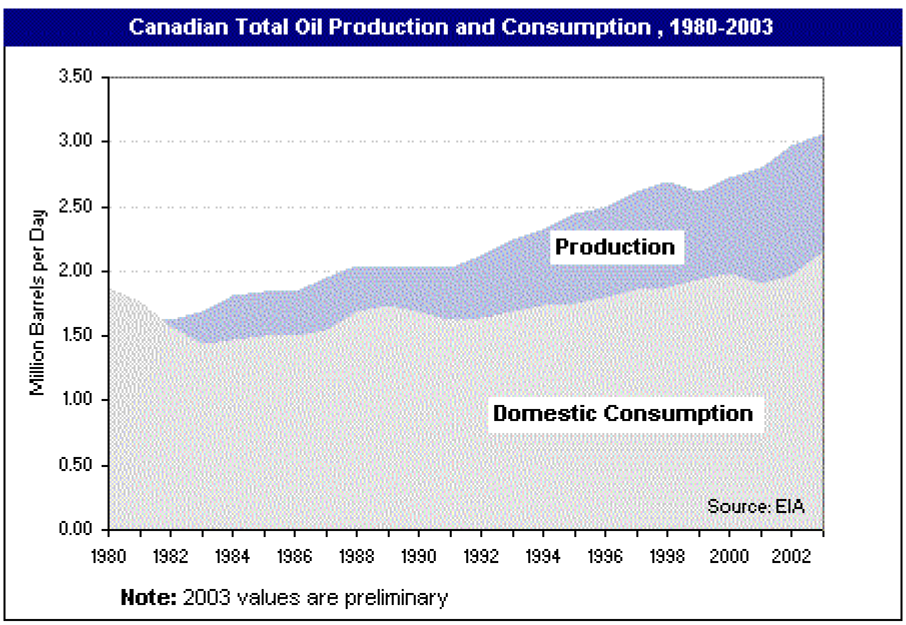
After expanding 3.3% in 2002, Canada's real gross domestic product (GDP) for 2003 grew 1.7%. A number of factors contributed to the slowdown of Canada's economy, such as weak U.S. economic growth for most of the year; a strong appreciation of the Canadian dollar; the SARS outbreak in Toronto; and restrictions on exports of softwood lumber and beef (due to mad cow disease). However, the recovery of the U.S. economy, high oil and natural gas prices, and continued spending from the Canadian government are expected to boost Canada's economy in 2004. The Canadian economy is forecast to grow 3.6% in 2004.

On December 12, 2003, Paul Martin was sworn in as Canada's 21st prime minister, after the resignation of fellow Liberal party member Jean Chrétien. On taking office, Prime Minister Martin pledged to work on strengthening U.S. - Canada relations and to increase spending on defense, healthcare, and education, as well as to improve federal-provincial relations. Mr. Martin, the leader of the liberal Party, is expected to call national elections for spring 2004.

ENERGY OVERVIEW

Canada was the fifth-largest energy producer in the world in 2001, behind the United States, Russia, China, and Saudi Arabia. Over the past two decades, Canada has become a significant net energy exporter. In 2001, about 31% of Canadian energy production was exported, with the United States its main customer. In the first three quarters of 2003, the United States imported more oil (including crude oil and petroleum products) from Canada than from any other country. During the same time period, the United States also imported about 2.5 trillion cubic feet (Tcf) of Canadian natural gas, representing 87% of total U.S. natural gas imports. In 2001, about 39% of Canada's primary energy production was natural gas, followed by oil (25%), hydropower (20%), coal (11%), and nuclear power (5%). Alberta is Canada's largest producer of energy. Along with being a major energy-producer, Canada also was a significant energy consumer in 2001, ranking eighth in the world.

OIL



According to *Oil & Gas Journal*, as of January 2004, Canada's total proven crude oil reserves stood at 178.9 billion barrels. Canada currently trails only Saudi Arabia, which holds the most proven crude oil reserves in the world. Prior to 2002, Canada did not even rank in the top 20 of countries with the most proven crude oil reserves. The massive increase in reserves reflects the *Journal's* inclusion of Alberta's oil sands, which stood at 174.4 billion barrels as of January 2004, according to Alberta Energy and Utilities Board (EUB). In contrast, conventional crude oil and condensate stood at an estimated 4.5 billion barrels, as reported by Canadian Association of Petroleum Producers (CAPP). Some analysts, however, have questioned the new assessment and whether it is accurate and appropriate to include oil sands.

Exploration and Production

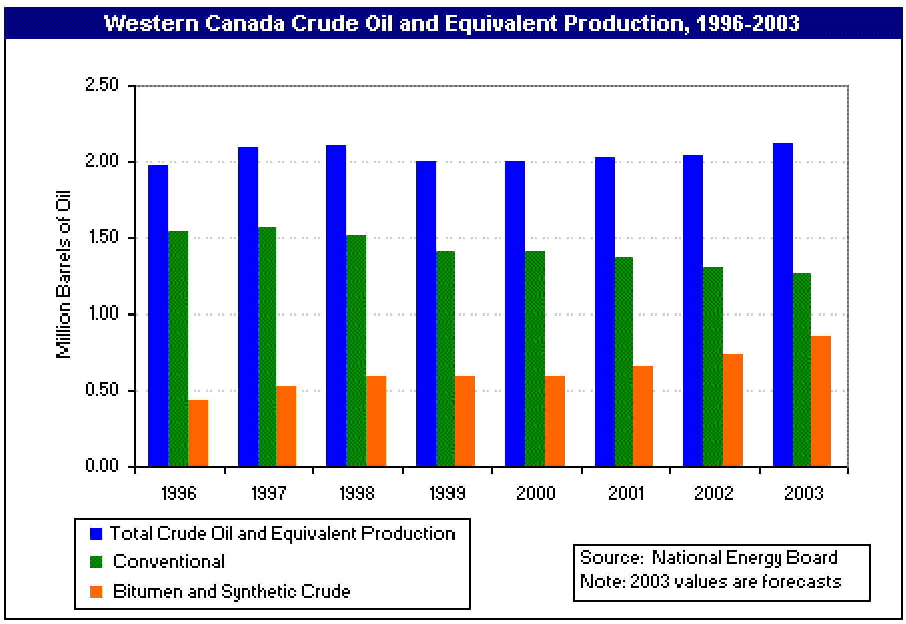
Canada's total oil production (including all liquids, bitumen and synthetic crude) averaged an estimated 3.1 million barrels per day (bbl/d) for 2003, an increase of 7% over 2002. The country's oil production has been increasing since 1999, as new oil sands projects and production off the coast of Newfoundland have come onstream. Overall, oil sands production is expected to increase significantly and to offset the decline in conventional crude oil production, becoming Canada's major source of oil supply.

Western Canada Sedimentary Basin

The Western Canada Sedimentary Basin (WCSB), underlying most of Alberta and parts of British Columbia, Saskatchewan, Manitoba and the Northwest Territories, has been the main source of Canadian oil production for the past 50 years. Alberta, however, has been the primary oil producer not only for the region but also for the entire country.

Although conventional oil production in Alberta and in the WCSB as a whole has been declining, increased output of non-upgraded bitumen and synthetic crude (crude oil which has been upgraded from raw bitumen) from oil sands has compensated for the shortfall in conventional supplies (see table). According to EUB's *Alberta's Reserves 2002 and Supply/Demand Outlook 2003-2012*, total raw bitumen production in Alberta during 2001exceeded total conventional crude oil production in the province for the first time. In 2002, production of non-upgraded bitumen and synthetic crude averaged combined 743,738 bbl/d while conventional crude oil production (light, medium and heavy grades) averaged an estimated 660,551 bbl/d. The report also forecasts that combined production from conventional and oil sands is expected to reach 2.7 million bbl/d by 2012, of which 77% will be supplied from oil sands.

Atlantic Coast



Crude oil production off the coast of Newfoundland has increased significantly in the past few years. According to preliminary estimates from Canada's National Energy Board (NEB), oil production off the coast of Newfoundland is forecast to reach 346,000 bbl/d for 2003, an increase of 132% since 2001. Exploration and production activity on Canada's east coast is carried out in the Jeanne d'Arc Basin, offshore Newfoundland. The climate demands technologically advanced offshore oil platforms, able to withstand extremely cold temperatures, icebergs and high winds, adding to production costs.

The first project in Canada's Atlantic coast regioncame onstream in November 1997. The field, known as Hibernia, is located 197 miles east-southeast of St. John's, Newfoundland. Production has increased rapidly since Hibernia's startup. From January to October 2003, the field averaged nearly 200,000 bbl/d. An additional reservoir, Avalon, came onstream in May 2000 and has averaged 5,668 bbl/d over the same time period. The area also contains natural gas, which currently is being re-injected into the Hibernia reservoir to increase the oil recovery rate from the field. ExxonMobil Canada is the operator, with joint venture partners Chevron Canada, Petro-Canada, Canada Hibernia Holding Corporation, Murphy Oil, and Norsk Hydro.

A second project, Terra Nova, began production in January 2002. Crude oil extracted from Terra Nova's reservoir on the ocean floor is routed upward to the Terra Nova floating production storage and offloading vessel (FPSO), a storage vessel that processes the crude oil on deck. The petroleum is then transferred to shuttle tankers that take the oil to market. From January to October 2003, the field averaged 131,882 bbl/d. Petro-Canada is the operator of the field, with other partners including ExxonMobil, Norsk Hydro, Husky Oil Operations, Murphy Oil Corporation, Mosbacher Operating, and Chevron Canada Resources.

Other Developments

White Rose and Hebron/Ben-Nevis fields are two other projects that are currently under development. The White Rose field, which is operated by Husky Oil Operations, is expected to begin production in 2005 or early 2006. The field could reach an estimated 90,000 bbl/d at peak production. According to Husky Oil, the White Rose field also holds an estimated 2.5 Tcf of natural gas that also could be produced eventually if proven economically viable.

In February 2002, the Hebron/Ben-Nevis project was suspended indefinitely by ChevronTexaco (operator). The company indicated that the field was not economical viable due to significant challenges in developing scattered deposits, in addition to the high viscosity of the oil, which increases production costs. In October 2003, ChevronTexaco, along with its partners -- ExxonMobil, Norsk Hydro and Petro-Canada -- indicated that they have been reconsidering the project and eventually may develop it.

Besides the Hebron/There have been other setbacks off the east coast of Canada. In early June 2003, Petro-Canada and partners, EnCana and Norsk Hydro, abandoned exploration activities in the Flemish Pass Basin after the exploration well, Mizzen L-11, did not produce enough oil to make the well commercially viable. The partners subsequently abandoned the second prospect, Tuckamore B-27.

On December 17, 2003, the Canada-Newfoundland Offshore Petroleum Board auctioned exploration rights for eight out of 14 concessions, with ChevronTexaco, ExxonMobil and Imperial Oil purchasing rights to explore for oil in the Orphan Basin. Orphan is located in deep waters north of the Jeanne d'Arc Basin. According to a recent seismic study, there are four large reservoirs, with each potentially holding up to 1 billion barrels of oil. Exploration activities for oil are also being conducted onshore in both New Brunswick and Nova Scotia.

Pacific Coast

The British Columbia government is pushing to lift a 30-year-old ban on exploration in the Pacific Ocean in order to begin production by 2010. The area near Queen Charlotte Basin is thought to hold as much as 10 billion barrels of oil. Queen Charlotte, Tofina, Winona and Georgia basins are expected to hold an estimated 43.4 Tcf of natural gas, according to British Columbia Ministry of Energy and Mines.

Synthetic Crude Oil

Oil sands contain deposits of bitumen (a heavy, black viscous oil). To process bitumen, it first must be extracted from the ground. There are two extraction methods. Shallow oil sands deposits, which can be excavated from the surface, and deeper "in situ" (in situ means "in place," indicating that the bitumen is separated underground) deposits which require other recovery methods, such as cyclic steam stimulation and steam-assisted gravity drainage (SAGD). These methods inject steam to help separate the bitumen from sand and clay and bring it to the surface. According to the Alberta Ministry of Energy, roughly two tons of oil sands must be dug up, moved and processed to produce one barrel of oil.

The extracted bitumen is then separated from sand and water, which it surrounds. Before it is sent to a refinery to be upgraded into high-quality oil called "synthetic crude," the bitumen must be diluted with lighter hydrocarbons to make it transportable by pipelines. At the refinery, the bitumen will be treated again and upgraded into synthetic crude. The upgrading process also generates other products, such as petroleum coke, which is either used to power the facility or sold.

The Athabasca Oil Sands deposit, in northern Alberta, is one of the two largest oil sands deposits in the world. There are also oil sands deposits on Melville Island, in the Canadian Arctic and two smaller deposits in northern Alberta, Peace River and Cold Lake.

Oil Sands Production

Mining

A majority of non-upgraded crude bitumen production to date has come from three surface mining projects which averaged a combined 526,510 bbl/d in 2002. A large portion of this production is then upgraded into synthetic crude oil. EUB has forecast mined bitumen production to reach 1.56 million bbl/d by 2012

The first project, Syncrude Canada Limited (a joint venture of eight companies with Canadian Oil Sands Investments Incorporated having the largest stake), was Canada's largest producer of both non-upgraded crude bitumen and synthetic crude from oil sands in 2002, averaging around 270,547 bbl/d and 230,000 bbl/d, respectively. Synthetic crude production is expected to reach 350,000 bbl/d after Syncrude completes stage 3 of its expansion program in 2005. Other planned production expansions (stages 4 and 5) will increase production to an estimated 550,000 bbl/d by around 2015.

Suncor Energy, the first company to begin processing Alberta oil sands (in 1967), averaged 258,400 bbl/d of non-upgraded crude bitumen and about 206,000 bbl/d of synthetic crude in 2002. In 2001, Suncor completed its Project Millennium, which increased production capacity of synthetic crude to 225,000 bbl/d. The company's next project, Voyageur, aims to increase production of synthetic crude to between 500,000-550,000 bbl/d in 2010 to 2012. The project has three stages: 1) expand existing upgrader; 2) increase bitumen supply through further development of the Firebag In-situ Oil Sands Project; and 3) establish a third oil sands upgrader.

The Athabasca Oil Sands Project is a joint venture of Shell Canada Limited, Chevron Canada Limited (a wholly owned subsidiary of ChevronTexaco Corporation) and Western Oil Sands Incorporated. The project has two components: the Muskeg River Mine; and the Scotford Upgrader, which is located in Fort Saskatchewan. Diluted bitumen is shipped from the Muskeg River Mine via the Corridor pipeline to the Scotford Upgrader, where the bitumen is upgraded into synthetic crude oil. Production of non-upgraded bitumen has increased steadily since coming onstream in December 2002, averaging 115,000 bbl/d in the third quarter of 2003. Expected capacity of the project is 155,000 bbl/d. Shell Canada currently is considering a long-term expansion program of the Athabasca project, with production eventually reaching 525,000 bbl/d of non-upgraded bitumen. Potential projects include the expansion of Muskeg River Mine to 225,000 bbl/d and development of Jackpine Mine Phase 1 and 2, which combined would produce 300,000 bbl/d. Shell, however, has not committed to a timeline.

Thermal (In-situ)

In 2002, non-upgraded crude bitumen production from in-situ operations averaged 299,843 bbl/d. Most of in-situ production to date has been marketed in non-upgraded form outside of Alberta and only a small percentage is used in Alberta refineries. EUB has forecast in-situ production to reach 773,647 bbl/d by 2012.

In 2003, there were 10 in-situ bitumen projects in operation. The most productive operation was

Imperial Oil's Cold Lake , which has averaged around 120,000 bbl/d over the past few years. In 2002, the company completed the Mahkeses (phases 11-13) project, which is expected to increase production to 150,000 bbl/d. Canadian Natural Resources (CNR) currently operates the second largest in-situ project in Alberta (Primrose/Wolf Lake), which produces approximately 40,000 bbl/d. CNR received regulatory approval on August 16, 2002 to expand its operations to more than 120,000 bbl/d. CNR also is developing its Horizon project, with initial production of 110,000 bbl/d, beginning in 2008.

Other Canadian in-situ projects in operation include: Japan Canada Oil Sands Limited Hangingstone Project, Petro-Canada McKay River Project; EnCana Corporation Christina Lake and Foster Creek projects; and Devon Energy Dover Project.

Developments

There are a number of oil sands projects that are being developed currently, such as ConocoPhillips' $1.1 billion Surmont oil sands project and Nexen and OptiCanada's Long Lake and Meadow Creek projects (start-up date 2006). Other companies developing oil sands projects include, Imperial, ExxonMobil, and Husky Energy.

In December 2003, Petro-Canada decided to delay plans to develop a new extraction facility at Meadow Lake, after projected costs escalated. The original plans called for production of 80,000 bbl/d, beginning in 2007. Petro-Canada instead opted to upgrade and to expand the capacity of its Edmonton refinery so that it could process bitumen-based feedstock into gasoline, diesel and other consumer end products.

Difficulties

A combination of high development costs, growing environmental concerns, and high natural gas prices have resulted in some companies delaying or downsizing projects in recent months. The extraction of bitumen, particularly underground (in-situ), requires significant amounts of natural gas and water. Natural gas is used not only to generate steam, which is injected into the ground to melt the mud away from the bitumen but also is used to generate electricity to power the massive shovels used for pit mining. Some analysts predict that if all proposed oil sand projects are realized, companies eventually will require up to 2 billion cubic feet per day of natural gas.

Future Kyoto requirements - Canada ratified the Protocol in December 2002 - could also raise costs, as companies would most likely have to invest in emission reducing technologies or acquire carbon credits to offset emissions resulting from production. Uncertainty about the potential impact of implementing the Kyoto Protocol prompted TrueNorth Energy in January 2003 to defer construction of its $3.5 billion Fort Hills Oil Sands Project. In addition, CNR initially postponed its giant Horizon project due to potential economic costs of reducing emissions. CNR decided to go ahead with the project only after the Canadian government assured oil sand companies that they would not be hindered by the associated costs of limiting emissions. The government temporarily placed a cap on the price of the credits in Canada that may have to be purchased to allow the companies to emit CO_2.

Canadian Oil Exports

Canada is a major source of U.S. oil imports. From January to October 2003, the United States imported 1.9 million bbl/d of oil from Canada (1.5 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 gasoline, jet fuel, distillate, etc., since 1996.

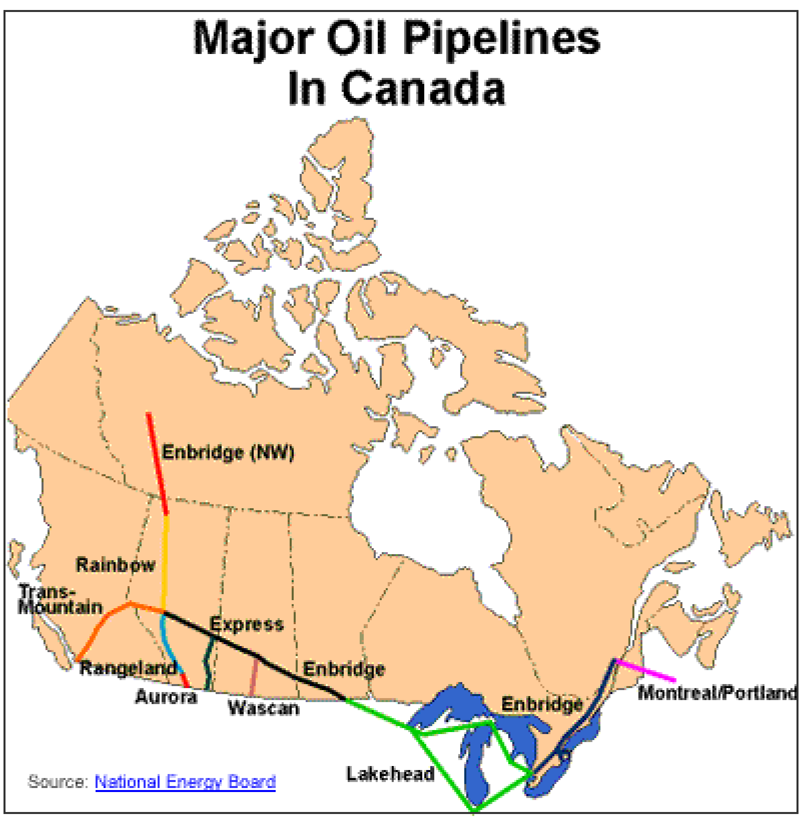
A majority of U.S.-bound Canadian oil exports go to the Midwest (PADD II). From January to October 2003, Canada exported 1.07 million bbl/d to PADD II, accounting for approximately 69% of PADD II's total oil imports. Canadian oil exports also dominate in the Rocky Mountain region (PADD IV), averaging 260,000 bbl/d during January - October 2003, and accounting for nearly 100% of the district's total oil imports. Canada also exports 569,000 bbl/d of its oil to the U.S. East Coast (PADD I) as well as, to a lesser extent, to the Gulf Coast region (PADD III) and the West Coast (PADD V).

Sector Organization

Canada's oil sector has seen significant mergers and acquisitions in recent years. In 2001, U.S. firms purchased over $35 billion in Canadian oil and natural gas assets, including Houston-based ConocoPhillip’s purchase of Gulf Canada for $8.9 billion and Devon Energy's (U.S.) acquisition of Canada's Anderson Exploration for $7.1 billion.

Canadian firms also have been busy reorganizing the country's oil patch. In April 2002, two of Canada's largest companies, Alberta Energy Company Limited and PanCanadian Energy Corporation, merged to create EnCana Corporation, country's largest non-integrated oil and natural gas producer (by market value).

However, it now appears that U.S. firms are beginning to retreat from Canada, particularly from assets held in Western Canada. Over the past year, El Paso, ChevronTexaco, Marathon Oil, ConocoPhillips, Vintage Oil, Hunt Oil, and Murphy Oil have made moves to divest conventional hydrocarbon assets (mainly natural gas). Canada's EnCana also made an announcement in November 2003 that it plans to sell (Canadian) $1 billion in assets. Analysts speculate that companies are putting their Canadian properties up for sale because many of these assets are mature or no longer economic viable. In the case of ChevronTexaco, the company reportedly is selling its assets in order to focus on higher-growth prospects in its global energy portfolio.



Pipelines

An extensive pipeline system transports western Canadian oil to eastern Canadian and U.S. markets. There are two major oil pipeline operators in Canada. The first is Enbridge Pipelines Incorporated which operates a 9,000-mile network of piping and terminals, delivering oil from Edmonton, Alberta, east to Montreal, Québec and eastern Canada, as well as to the U.S. Great Lakes region.

The other major Canadian pipeline operator is Terasen. The company operates 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. Terasen is currently in the process of increasing TMPL 's capacity by 30,000 bbl/d. The company also runs the Express pipeline which links Hardisty, Alberta to Casper, Wyoming. From there, the Express line connects to the Platte pipeline, which has a terminus in Wood River, Illinois.

With production from Alberta's oil sands increasing, Enbridge has been seeking to expand its U.S. export capacity through development and acquisition of pipelines. In April 2003, Enbridge completed the final stage to its Terrace Expansion Project. The first stage of the project linked Kerrobert, Saskatchewan to Clearbrook, Minnesota, adding approximately 210,000 bbl/d of capacity to the Enbridge network. The finally phase extended the line further into Minnesota, adding 140,000 bbl/d of capacity.

In September 2003, Enbridge acquired 90% stake in the Cushing to Chicago Pipeline System. The 650-mile pipeline has capacity of 300,000 bbl/d. Enbridge plans to reverse the flow of the pipeline in order to transport crude oil from Chicago to Cushing, allowing Canadian producers access to new markets in the U.S. Enbridge which plans to rename the pipeline Spearhead plans to have the reversal of the line completed in 2004.

In October 2003, Enbridge announced a proposed project to build a crude oil pipeline (Southern Access) from its existing terminal at Superior, Wisconsin, south to the Wood River hub in southern Illinois. The 630-mile pipeline is expected to have an initial capacity of 250,000 bbl/d and to interconnect with the abovementioned Spearhead pipeline. Enbridge expects to have it operational by 2007, pending regulatory approval.

Oil Sands Pipelines

Development of Alberta's massive oil sands deposits has required new pipelines to transport diluted bitumen from the mine to downstream processors and eventually to market terminals. Up to now, Canadian pipeline companies have focused on taking the Athabasca oil sands southward, to processing facilities in the Edmonton area. The first of these pipelines, the 344-mile Athabasca pipeline (Enbridge), was completed in April 1999 and connects Suncor's oil sands operations to the Enbridge network. The pipeline has potential capacity of 570,000 bbl/d. The second pipeline, Corridor (Terasen), connects the Muskeg River Mine to Shell's Scotford Refinery. Oil began to flow through the Corridor Pipeline in May 2003.

Currently both Terasen and Enbrigde are exploring possibilities of increasing their shipping capacity. Terasen recently revived its Bison Pipeline project after delaying it in May 2003. The plan calls for building a pipeline to transport diluted bitumen from mines and refineries near Fort McMurray to pipelines and processing plants in the Edmonton area. Terasen would increase the pipelines capacity over three stages: 1)172,000 bbl/d by 2006; 2) 320,000 bbl/d by 2008; and 3) 610,000 bbl/d by 2010. The final phase would include constructing a second pipeline parallel to the first. Whether the project continues to move forward is dependent upon whether Terasen can secure sufficient crude oil supplies in Fort McMurray.

Enbridge is exploring the possibility of building a new oil pipeline from the Athabasca oil sands region to the coast of British Columbia, for export to California or Asia by 2009. The project, called the Gateway Pipeline, would provide 400,000 bbl/d of capacity and would link Alberta either to Prince Rupert or to Kitimat, on the British Columbia coast, where ships would take crude oil and petroleum products to refineries in California and in Asia.

NATURAL GAS

As of January 2004, Canada's proven natural gas reserves stood at 59.1 Tcf. Canada produced about

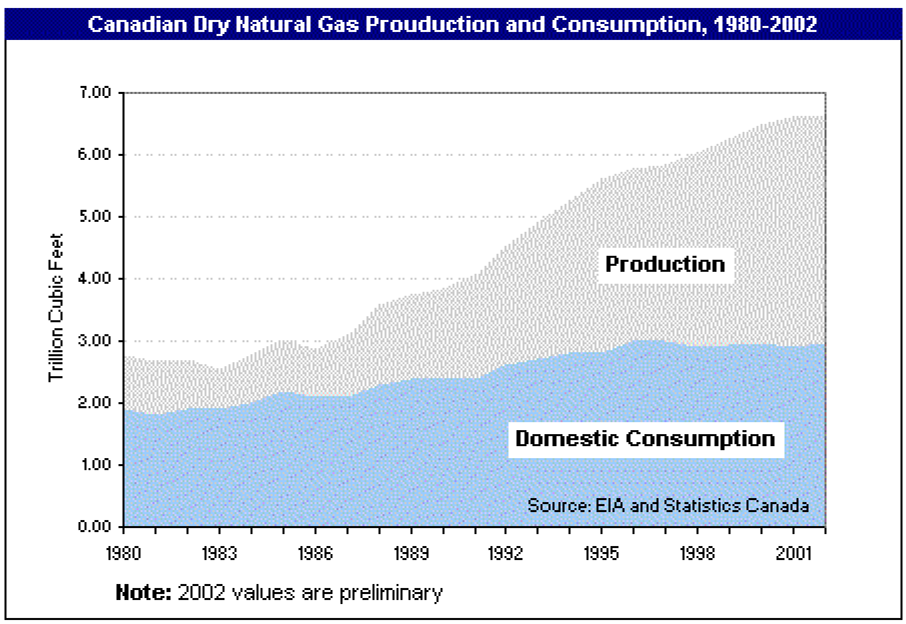
6.6 Tcf of natural gas in 2002, making it the world's third largest natural gas producer (after the United States and Russia) and second largest natural gas exporter (after Russia). Canada's natural gas exports go almost exclusively to the United States. Canadian natural gas consumption, 2.9 Tcf in 2002, is projected to grow in coming decades, largely for use in electricity generation and in production of oil sands.

Exploration and Production

Like the oil industry, Canada's natural gas industry is based primarily in the province of Alberta, which in recent years has accounted for nearly 70% of the country's natural gas output. Some analysts, however, forecast little growth potential for natural gas in Alberta, as well as for the entire Western Canada Sedimentary Basin (WCSB). Consequently, some companies have shifted their focus to newer projects in British Columbia, Atlantic Canada and the Arctic, as well as to new sources, such as imported liquefied natural gas (LNG) and coalbed methane.

Western Canada Sedimentary Basin

According to the National Energy Board's (NEB) *Short-term Natural Gas Deliverability from Western Canada Sedimentary Basin 2003-2005*, natural gas production in the region grew rapidly in the 1990s, from 10.7 billion cubic feet per day (Bcf/d) in 1990, to 16 Bcf/d in 1998. Since 1998, natural gas production in WCSB has averaged just above 16 Bcf/d. The report notes that between 1998 and 2002, new natural gas wells were able to offset the decline rate of older ones, resulting in the relatively static production rate for those years. As for the short-term outlook, natural gas production is expected to decline 3%, from 16.3 Bcf/d at the end of 2002, to 15.8 Bcf/d in 2005.



One reason for the decline, according to NEB, is that many of the new fields coming onstream are small and quickly depleted. While there are deeper and more prolific natural gas reserves in the Rocky Mountain foothills, they also are more expensive to develop. Nonetheless, NEB projected that if natural gas prices remain high, producers will continue to have incentive to exploit the many small natural gas pools in the WCSB, as well as coalbead methane, of which the region holds considerable reserves. Declining prospects in WCSB, however, have prompted some companies, such as ConocoPhillips, ChevronTexaco, Marathon, Vintage Petroleum, and Murphy Oil, to begin selling natural gas properties.

Another issue impacting natural gas output in the region is EUB's recent announcement (General Bulletin GB #2003-16) that ordered 938 natural gas wells in the Wabiska-McMurray region to be shut-in in order to ensure the recovery of 100 billion barrels of crude bitumen. According to studies, when natural gas is extracted from pools among oil sands, the pressure is reduced and can hinder thermal (SAGD) recovery of bitumen.

British Columbia

The Ladyfern field was touted as Canada's largest natural gas find in 15 years, after Murphy Oil drilled a well in 2002 that tested out 100 million cubic feet per day (Mmcf/d). The find resulted in a number of companies (Murphy, Apache, Canadian Natural Resources, and EnCana) buying property and over-drilling. The field's production, which peaked at about 700 Mmcf/d in 2002, has declined to about 300 Mmcf/d. Many analysts expect the field to be drained by 2004. On a positive note, Canadian Superior Energy reported in April 2003 that it had made two new natural gas discoveries at the East Ladyfern field, located 22 miles southeast from the Ladyfern main field.

In May 2003, the British Columbia government announced a package of royalty credits in an effort to attract new investment in region. The government plans to double natural gas production by 2008 from the current 900 Bcf per year. As mentioned before, the British Columbia government hopes to lift the moratorium on offshore drilling, giving access to an estimated 43.4 Tcf of natural gas. British Columbia also has three onshore basins - Whitehorse Trough, Bowser, and Nechako - with combined estimated reserves of 23.2 Tcf.

Atlantic Coast

Most of Eastern Canada’s natural gas production takes place off the coast of Nova Scotia, on the Scotian Basin. Similar to oil production in this region, companies have been reevaluating their offshore projects. In 2003, Shell downgraded the reserve base of the Sable Offshore Energy Project (SOEP) by 11%, to 700 Bcf. Shell had originally estimated Sable reserves to hold 1.1 Tcf, but in January 2002, the company revised that estimate downwards to 800 Bcf. The project, which began production in late December 1999, is currently in the second stage of development, with the fourth field, Alma, beginning natural gas production on December 2, 2003. Two subsequent fields, South Venture and Glenelg, will be phased in as necessary to maintain current (500 Mmcf/d of natural gas and 20,000 bbl/d natural gas liquids) or expected natural gas production volumes. Natural gas is transported through an underwater pipeline to the consortium's onshore processing facilities in Goldboro, Nova Scotia, and distributed to the Canadian provinces of Nova Scotia and New Brunswick, as well as to the United States. A consortium of ExxonMobil Canada (50.8%), Shell Canada (31.3%), Imperial Oil Resources (9%), Pengrowth Corporation (8.4%) and Mosbacher Operating Limited (0.5%) own the offshore assets of the Sable Project.

Another project on the Scotian Shelf, Deep Panuke, is unlikely to be developed in the near-term. In December 2003, EnCana announced that it decided to withdraw its original applications for the development of the Deep Panuke reserve. Despite encouraging results from two exploration wells drilled during the past summer, EnCana stated that the original development plan was no longer appropriate, but would consider potentially developing a smaller production facility.

Despite these setbacks, Canadian Superior Energy, in conjunction with the El Paso Corporation, remains optimistic about finding economic viable natural gas reserves off the coast of Nova Scotia. In 2003, the two companies drilled exploration wells at their "Mariner" block (EL 2409), just north of the eastern end of Sable Island, and at their "Marquis" blocks (EL 2401, 2402), which are near the Deep Panuke field. In 2004, Canadian Superior and El Paso plan to drill an exploration well at their "Mayflower" block (EL 2406), located approximately 285 miles straight East of Boston, Massachusetts.

Nonetheless, analysts remain skeptical of Nova Scotia’s offshore potential. A recent report from Canada’s National Energy Board concluded that the Scotian Basin “is a relatively unexplored geological basin that has considerable potential for new discoveries and increased levels of natural gas production.” The report also added that exploration in this region is “a risky and costly endeavor,” which ultimately may discourage further investment.

Arctic

The Mackenzie Delta, located in the Northwest Territories, also holds significant amount of natural gas (9 to 10 Tcf). Natural gas from the region could begin flowing to southern markets by 2010 if the MacKenzie Gas Project is realized according to plan. The project focuses on developing three proven natural gas fields in the Delta: Imperial's Taglu field (estimated reserves: 3 Tcf); Conoco's Parsons Lake (estimated reserves: 1.8 Tcf); and Shell's and ExxonMobil's Niglintgak (estimated reserves: 1 Tcf). Other companies conducting exploration activities in the region include Petro-Canada, Anadarko, Devon, Apache, BP, and Burlington Resources.

Liquefied Natural Gas

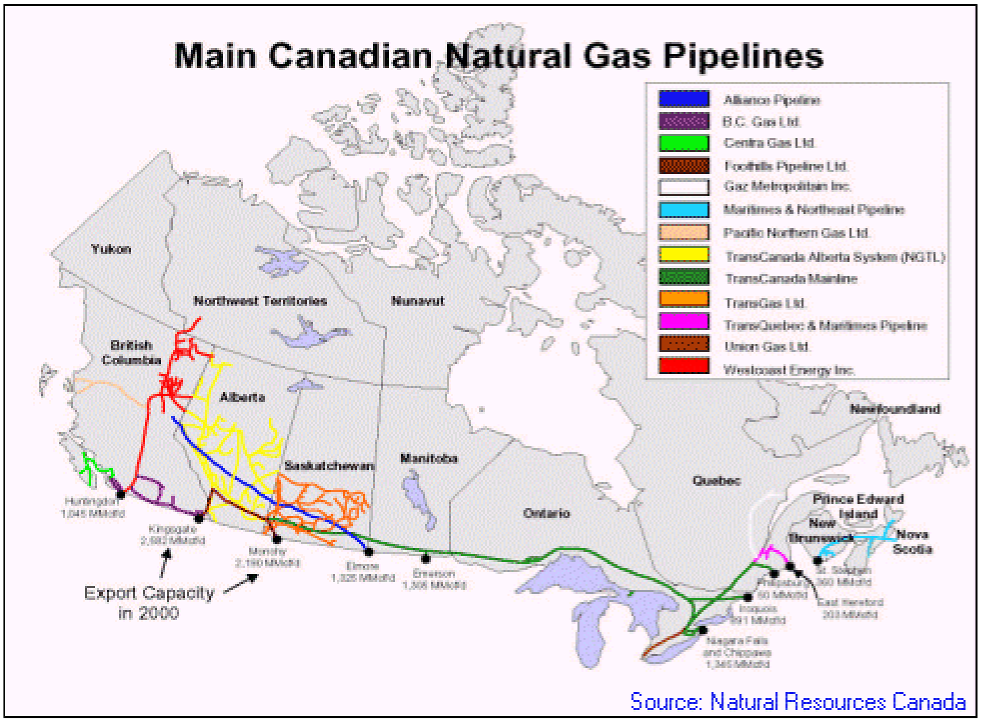
Irving Oil announced in June 2003 that it would proceed with an environmental assessment and other regulatory work for a proposed LNG import facility at Canaport, near Saint John, New Brunswick. The facility has an in-service date of 2006, with an expected capacity of 500 Mmcf/d. In August 2003, Access Northeast Energy (ANE) announced plans to construct a LNG regasification facility in Nova Scotia on the Strait of Canso. The facility, dubbed Bear Head, would have a capacity between 750 Mmcf/d and 1 Bcf/d. ANE would connect the facility to the Maritimes and Northeast pipeline to transport natural gas to Canadian and U.S. markets. The facility is expected to enter operation in fall 2007, assuming full regulatory approval.

Coalbed Methane

Coalbed methane (CBM) production is still in its infancy in Canada, with the first wells being drilled in 1997 and actual commercial production beginning in 2002. EnCana and MGV Energy Incorporated are the only companies currently producing commercially natural gas from coalbed methane. Both companies plan to expand their operations, with EnCana expecting to drill 300 wells in the region in 2004, increasing production from 3 Mmcf/d to 30 Mmcf/d by the end of the year. MGV has drilled about 180 wells in Alberta's Gayford and Horseshoe Canyon areas in 2003, and plans to drill an additional 300 wells in 2004. EOG Resources, Burlington Resources, Anadarko and Nexen Energy also are planning to move forward with coalbed methane pilot projects in the coming year.

As recent report prepared by the Alberta Geological Study, a division of the EUB, reported that the province's coalbed methane reserves could be as large as 500 Tcf. Overall, there is little agreement on how much natural gas Canada's coal seams could contain, with total CBM reserve estimates ranging from 145 Tcf to 3,000 Tcf.

Other unconventional natural gas resources in Canada include shale gas and gas hydrates. In December 2003, an international partnership, including the U.S. Geological Survey, the U.S. Department of Energy, Canada, Japan, India, Germany, and a number of energy companies, successfully proved that it is technically feasible to produce natural gas from gas hydrates. The group conducted test drilling at the Mallik field, a site in the Mackenzie River Delta of the Northwest Territories. Gas hydrates are ice-like substances composed of water and natural gas that form under conditions of low temperature and high pressure. Gas hydrates also are highly concentrated - one solid cubic meter converts to 5792 cubic feet of natural gas. More importantly, there are massive reserves of gas hydrates, located mainly under marine continental shelves. It is estimated that gas hydrates contain more energy than all other hydrocarbons in the world combined.



Source: Natural Resources Canada

Pipelines
Canada has a number of natural gas pipelines connecting to the United States. The 1,875 mile-Alliance Pipeline links western Canada (Fort St. John, British Columbia) to the Chicago region. The pipeline has a transportation capacity of 1.3 Bcf/d. The Alliance pipeline entered into commercial service on December 1, 2000.

Atlantic
The Maritimes and Northeast Pipeline (M&NE) came onstream in January 2000. M&NE delivers natural gas from Canada's Sable Island area to Nova Scotia, New Brunswick and New England. The pipeline interconnects with the existing U.S. pipeline grid in Dracut, Massachusetts. There are plans to expand the pipeline's capacity, as well as to link the line to Prince Edward Island, Cape Breton, and northern New Brunswick. However, the lack of a recent major natural gas discovery has slowed expansion of the pipeline. The pipeline's current capacity is about 530 Mmcf/d.

In October 2001, El Paso Corporation announced plans to build an undersea natural gas pipeline off the coast of Nova Scotia - called the Blue Atlantic Transmission System. El Paso, however, decided in April 2003 to postpone development of the project, as major oil and natural gas companies operating off the coast of Nova Scotia had announced plans to forgo drilling activities for this year. The Blue Atlantic group plans to resume development when drilling activities continue. The proposed 750-mile pipeline would have a transportation capacity of 1 Bcf/d, connecting first to Nova Scotia and then continuing underwater to New York and New Jersey.

In September 2002, the 700 Mmcf/d-Millennium Pipeline, which would carry Canadian natural gas from Lake Erie to New York City, won U.S. regulatory approval from the Federal Energy Regulatory Commission (FERC). Though the pipeline won FERC endorsement, the New York Department of Environmental Conservation found that Millennium's proposed crossing of the Hudson River at Haverstraw Bay was not consistent with the Coastal Zone Management Act (CZMA) and, accordingly, denied the pipeline a state permit. In response, the Millennium group filed an appeal in June 2003 with the U.S. Department of Commerce. This appeal, however, was rejected on December 15, 2003. The Millennium group still remains hopeful that it can find an amenable alternative route.

Arctic

In June 2003, TransCanada Pipelines agreed to lend the Aboriginal Pipeline Group (APG) funds to pay for its share in the preliminary feasibility study of the Mackenzie Delta Pipeline. APG represents the interests of Aboriginal people in the Northwest Territories in regards to Mackenzie Delta natural gas pipeline. The project had been delayed as APG had difficulty in raising the required funds for their share. The deal also gives APG one-third ownership in the 850-mile pipeline. In return for the loan, TransCanada could end up with the natural gas it needs to ensure its main pipeline stays full as production declines in Alberta. The company also gets a small stake in the line along with the right to boost its ownership over time. With the agreement signed, the group of natural gas producers led by Imperial Oil filed a preliminary information package with regulators -- the initial step in the long process of getting approval to build the new pipeline.

The Mackenzie Delta pipeline would bring natural gas deposits (5.8 Tcf) owned by Imperial Oil, ConocoPhillips, ExxonMobil, Shell Canada and other large energy companies in the Mackenzie Delta northwest of Inuvik to southern markets. It also is expected that the pipeline would open large parts of the Canadian Arctic to exploration, as energy companies try to replace dwindling reserves and feed growing natural gas markets in Canada and the United States. There is already discussion of expanding the pipeline's capacity from 1.2 Bcf/d to 1.9 Bcf/d, as well as building a parallel pipeline to transport natural gas liquids.

COAL

Canada is a major coal producer and consumer, with estimated 2001 output of 77.7 million short tons (Mmst), consumption of about 72.6 Mmst, and reserves of 7.2 billion short tons. 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 (90%) for electricity generation, with the remainder mainly used for steel-making. About 80% of Canada's coal exports are for metallurgical purposes, with Japan and South Korea representing the country's largest customers.

ELECTRICITY

Canadian electricity generation in 2001 totaled 566.3 billion kilowatt hours (Bkwh), of which 56% was hydropower, 28.3% was conventional thermal power (oil, natural gas, and coal), 13% was nuclear generation, and 1.3% was other renewable sources. Canada was the largest producer of hydropower in the world in 2001. Trends in coming years are expected to favor thermal power generation, mainly natural gas-fired. Canadian nuclear output increased 6%, to 72.9 Bkwh, in 2001. Output, however, is much lower than its peak of 102.4 Bkwh in 1994. Ontario contains the bulk of Canadian nuclear capacity.

Exports

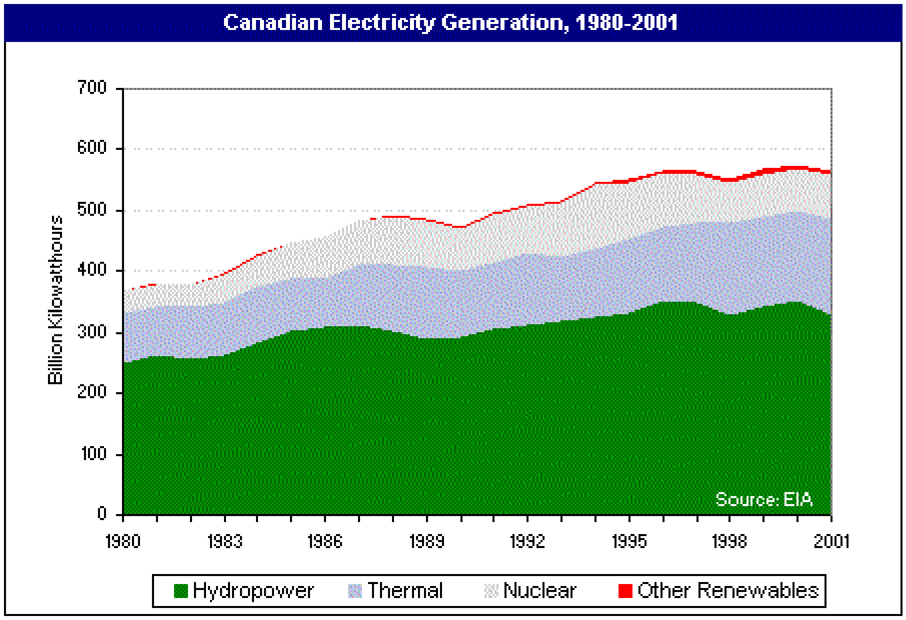
Canadian gross electricity exports to the United States averaged 39.6 Bkwh between 1992 and 2001. Most of the exports originate from the hydro-rich provinces, such as Québec, Manitoba, and British Columbia. These provinces have also accounted for a majority of exports in recent years. The National Energy Board (NEB) reported that exports have begun to decline over the last few years as domestic demand increased and generation capacity remained the same.

Imports

There exists considerable reciprocity between the Canadian and U.S. power markets, as the United

States also exports electricity to Canada (18 Bkwh in 2001). In 2002, imports from the United States increased in Ontario due to nuclear power plant closures. British Columbia and Québec have also increased imports, taking advantage of improved access to electricity market in the United States. According to NEB, net exports have decreased significantly since 1996, as imports from the United States continue to increase. A number of the Provinces have expressed interest in constructing more electricity lines to the United States, as well as in participating in U.S. Regional Transmission Organizations (RTO).

Restructuring
Under Canada's constitution, electricity regulatory authority falls under the jurisdiction of the provinces. In most provinces, a few dominant utilities provide the bulk of generation, transmission, and distribution. Although some of these utilities are privately owned, the provinces own most of them. There is also limited independent power producer (IPP) generation, mostly for sales to the larger utilities.



The process of restructuring has varied across the Canadian provinces. For example, in Nova Scotia, Newfoundland and Labrador, Yukon Territory, Northwest Territories and Nunavut, public utility boards still regulate electricity prices. Alberta and Ontario, which together account for about half of Canada's electricity market, have made efforts to deregulate their power sectors. Full deregulation began in Alberta in January 2001, and in Ontario in May 2002. In both provinces, electricity prices spiked shortly following initial deregulation, causing provincial governments to freeze the electricity prices charged to consumers, and to pay the difference to electric companies out of the government budget.

A newly elected government in Ontario, however, has made moves to lift the price cap on electricity in the province. In November 2003, the Ontario government introduced the Ontario Energy Board Amendment Act, 2003, which would remove the current 4.3-cent per kilowatthour price freeze in favor of a pricing structure that better reflects the true cost of electricity in the province. Although Alberta is open to competition, residential consumers in the province still have the option to purchase electricity at regulated rates until June 30, 2006.

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 2001, Canada consumed 13 quadrillion Btu of energy and emitted 156 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.

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: Paul Martin (since 12/12/03)
Independence: July 1, 1867 (from UK)
Population (2003E): 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, Québec, Saskatchewan, Yukon Territory*
Major Cities: Toronto, Montreal, Vancouver, Ottawa (capital), Edmonton, Calgary, Winnipeg, Québec
Languages: English (official), French (official)
Ethnic Groups: British Isles origin (28%), French origin (23%), other European (15%), Amerindian (2%), other, mostly Asian, African, Arab (6%), mixed background (26%)
Religions: Roman Catholic (46%), Protestant (36%), other (18%)

ECONOMIC OVERVIEW
Minister of Finance: Ralph Goodale
Currency: Canadian Dollar
Exchange Rate (1/20/04): $1 U.S. = $1.30 Canadian dollars
Nominal Gross Domestic Product (GDP) (2003E): $869 billion
Real GDP Growth Rate (2002E): 3.3% **(2003E):** 1.7% **(2004F):** 3.6%
Inflation Rate (consumer prices, 2002E): 2.2% **(2003E):** 2.8% **(2004F):** 1.0%
Unemployment Rate (2002E): 7.6% **(2003E):** 7.7% **(2004F):** 7.5%
Merchandise Exports (2002E): $264 billion
Merchandise Imports (2002E): $227 billion
Merchandise Trade Surplus (2002E): $37 billion
Current Account Balance (2002E): $15 billion
Major Export Products: Motor vehicles and parts, newsprint, wood pulp, timber, crude petroleum, machinery, natural gas, aluminum, telecommunications equipment, electricity
Main Destinations of Exports (2002E): the United States (84%), Japan (2.5%), United Kingdom (1.5%)
Major Import Products: Machinery and equipment, crude oil, chemicals, motor vehicles and parts, durable consumer goods, electricity
Main Origins of Imports (2002E): the United States (72%), Japan (3.3%), United Kingdom (2.9%)

ENERGY OVERVIEW
Minister of Natural Resources: John Efford
Conventional Crude Oil Reserves (1/1/04E): 4.5 billion barrels, according to *Oil and Gas Journal*

Oil Sands Reserves (1/1/04E): 174.4 billion barrels, according to *Oil and Gas Journal*
Oil Production (2003E): 3.1 million bbl/d, of which 2.3 million bbl/d was crude oil

Oil Consumption (2003E): 2.2 million bbl/d
Net Oil Exports (2003E): 0.9 million bbl/d
Oil Exports to the United States (Jan.- Oct. 2003E): 1.9 million bbl/d, 1.5 million bbl/d of which was crude oil (Québec, Ontario and the Atlantic provinces import around 900,000 bbl/d of crude oil)
Oil Imports from the United States (Jan.- Oct. 2003): 144,000 bbl/d
Natural Gas Reserves (1/1/04E): 59.1 trillion cubic feet (Tcf)
Natural Gas Production (2002E): 6.6 Tcf, according to data from *Statistics Canada*
Natural Gas Consumption (2002E): 2.9 Tcf, according to data from *Statistics Canada*
Net Natural Gas Exports (2002E): 3.7 Tcf, according to data from *Statistics Canada* (100% to the U.S.)
Coal Reserves (2001E): 7.2 billion short tons
Coal Production (2001E): 77.7 million short tons (Mmst)
Coal Consumption (2001E): 72.6 Mmst
Electric Generation Capacity (2001E): 111 million kilowatts
Electricity Generation (2001E): 566.3 billion kilowatthours (Bkwh) (56% hydro, 28.3% thermal, 13% nuclear, 1.3% geothermal and other)
Electricity Consumption (2001E): 504.4 Bkwh
U.S. Gross Imports from Canada (2002E): 36 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Environment: David Anderson
Total Energy Consumption (2001): 12.5 quadrillion British thermal unit (Btu)* (3.1% of world total energy consumption)
Energy-Related Carbon Emissions (2001): 156.2 million metric tons of carbon (2.5% of world carbon emissions)
Per Capita Energy Consumption (2001): 403 million Btu (vs U.S. value of 341.08 million Btu)
Per Capita Carbon Emissions (2001): 5.1 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (2001): 15,026 Btu/ $1995 (vs U.S. value of 10,810 Btu/ $1995)**
Carbon Intensity (2001): 0.19 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**
Fuel Share of Energy Consumption (2001): Oil (30.3%), Hydro (27.3%), Natural Gas (23.6%), Coal (13.5%), Nuclear (6.6%)
Fuel Share of Carbon Emissions (2001): Oil (45.1%), Natural Gas (27.9%), Coal (27.0%)
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 29, 1998 and ratified on December 17, 2002), 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 figures from OECD estimates based on purchasing power parity (PPP) exchange rates.

OIL and GAS INDUSTRIES
Organization: private sector (major companies: ExxonMobil's Imperial Oil, Royal Dutch/Shell's Shell Canada, Petro-Canada, Suncor, EnCana).
Major Oil and Gas Producing Provinces: Alberta; British Columbia; Saskatchewan; Nova Scotia; Newfoundland
Major Oil Pipelines: Terasen; Enbridge
Oil Refining Capacity (January 2004): Ontario (545,200 bbl/d); Alberta (441,300 bbl/d); Québec (449,900 bbl/d); New Brunswick (250,000 bbl/d); British Columbia (62,250 bbl/d); Newfoundland (105,000 bbl/d); Nova Scotia (82,200 bbl/d); Saskatchewan (52,000 bbl/d)
Major Gas Pipeline Companies: Enbridge, TransCanada PipeLines Ltd.

Sources for this report include: Access Northeast Energy; Alberta Energy and Utilities Board; British Columbia Ministry of Energy and Mines; Cambridge Energy Research Associates; Canadian Association of Petroleum Producers; Canada's National Energy Board; Canadian Business; CIA World Factbook; ConocoPhillips; Deutsche Bank; Devon Energy ; Dow Jones; Economist Intelligence Unit ViewsWire; Enbridge Pipelines; EnCana Energy Corporation; Energy Daily; ExxonMobil; Foster Natural Gas Report; Financial Times; Gas Daily; Global Insight; Husky Energy ; Imperial Oil; International Energy Agency; Natural Gas Week; Newfoundland Offshore Petroleum Board; New York Times; Nova Scotia Department of Energy; Oil and Gas Journal; Oil and Gas Investor; Oil Daily; Oilweek; Petro-Canada; Petroleum Economist; Petroleum Intelligence Weekly; Pipeline and Gas Journal; Platt's; Shell Canada; Statistics Canada; Suncor; Syncrude; Terasen; TransCanada Pipelines; U.S. Energy Information Administration; World Markets Online.

LINKS

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EIA - Country Information on Canada
APEC: Energy Issues and Trends

Links to other U.S. Government sites:
CIA World Factbook - Canada
U.S. Department of Energy's Office of Fossil Energy's International section - Canada
U.S. Department of Energy on Electricity Trade and Canada
U.S. Department of State Country Background Notes - Canada
U.S. Department of State Country Report on Economic Policy and Trade Practices
U.S. Embassy in Canada
U.S. International Trade Administration, Country Commercial Guide - Canada

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Associations and Institutes

Canadian Association of Oilwell Drilling Contractors
Canadian Association of Petroleum Producers
Canadian Centre for Energy Information
Canadian Electricity Association
Canadian Energy Pipeline Association
Canadian Energy Research Institute
Canadian Wind Energy Association
Energy Council of Canada
Oil Sands Discovery Centre
The Coal Association of Canada

Electric Generation
Atomic Energy of Canada Limited (AECL)
British Columbia Hydro
Hydro-Québec
Ontario Power Generation
SaskPower

Government
Alberta Department of Energy
Alberta Energy and Utilities Board
British Columbia Ministry of Energy and Mines
Manitoba Petroleum Division
National Energy Board of Canada
Natural Resources Canada, Energy Sector Nova Scotia Department of Energy
New Brunswick Ministry of Energy
Newfoundland and Labrador Ministry of Mines and Energy
Newfoundland Offshore Petroleum Board
Northwest Territories Government, Oil and Gas Division
Nova Scotia Offshore Petroleum Board
Ontario Ministry of Energy
Québec Ministry of Energy
Saskatchewan Industry and Resources

Oil and Natural Gas Companies
Anadarko Petroleum Corporation
Apache Canada Limited
BP Canada
Burlington Resources Incorporated
Canadian Natural Resources Limited
Canadian Superior Energy Incorporated
ChevronTexaco Canada
ConocoPhillips Canada
Deer Creek Energy Limited
Devon Energy
EnCana
EOG Resources
Husky Energy
Imperial Oil
Japan Canada Oil Sands Limited
Murphy Oil Corporation

Nexen Incorporated
Norsk Hydro Canada
Petro-Canada
Opti Canada Incorporated
Shell Canada Limited
Suncor Energy
Syncrude

Pipelines
Aboriginal Pipeline Group
Alliance Pipeline
Athabasca pipeline
Corridor Pipeline
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