BURLINGTON RESOURCES 2004 ANNUAL REPORT FORM 10-K

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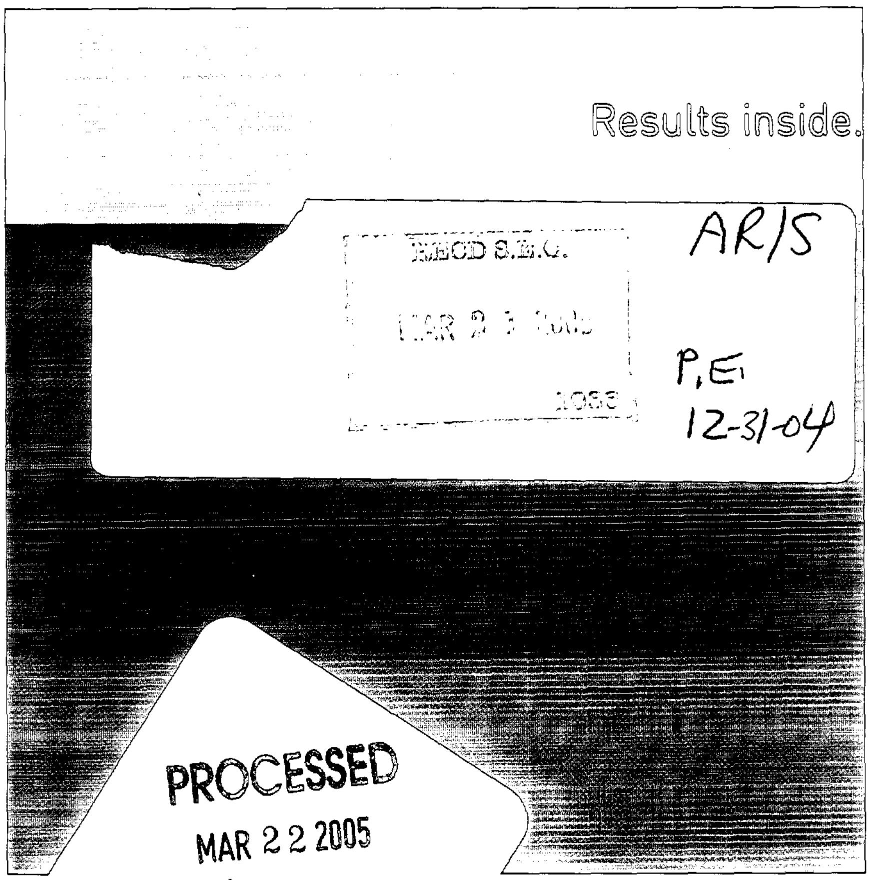
Why Burlington Resources?



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BURLINGTON™
RESOURCES

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-9971

BURLINGTON RESOURCES INC.

Incorporated in the State of Delaware | Employer Identification No. 91-1413284

717 Texas, Suite 2100, Houston, Texas 77002
Telephone: (713) 624-9500

Securities registered pursuant to Section 12(b) of the Act:
Common Stock, par value $.01 per share

Preferred Stock Purchase Rights

The above securities are registered on the New York Stock Exchange.

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No ____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes __X__ No ____

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of January 30, 2005 and as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of January 31, 2005: $16,915,639,395 and as of June 30, 2004: $14,035,722,348.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $.01 per share, on January 31, 2005, Shares Outstanding: 386,997,012

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated:

Burlington Resources Inc. definitive proxy statement, to be filed not later than 120 days after the end of the fiscal year covered by this report, is incorporated by reference into Part III.

Below are definitions of key certain technical industry terms used in this Form 10-K.

Bbls	Barrels	**MMBbls**	Millions of Barrels
BCF	Billion Cubic Feet	**MMBTU**	Million British Thermal Units
BCFE	Billion Cubic Feet of Gas Equivalent	**MMCF**	Million Cubic Feet
DD&A	Depreciation, Depletion and Amortization	**MMCFE**	Million Cubic Feet of Gas Equivalent
MBbls	Thousands of Barrels	**NGLs**	Natural Gas Liquids
MCF	Thousand Cubic Feet	**TCF**	Trillion Cubic Feet
MCFE	Thousand Cubic Feet of Gas Equivalent	**TCFE**	Trillion Cubic Feet of Gas Equivalent

Appraisal well is a well drilled in the vicinity of a discovery or wildcat well in order to evaluate the extent and importance of the discovery.

Basin is a synclinal structure in the subsurface that is composed of sedimentary rock and regarded as a good prospect for exploration.

Call options are contracts giving the holder (purchaser) the right, but not the obligation, to buy (call) a specified item at a fixed price (exercise or strike price) during a specified period. The purchaser pays a nonrefundable fee (the premium) to the seller (writer).

Cash-flow hedges are derivative instruments used to mitigate the risk of variability in cash flows from crude oil and natural gas sales due to changes in market prices. Examples of such derivative instruments include fixed-price swaps, fixed-price swaps combined with basis swaps, purchased put options, costless collars (purchased put options and written call options) and producer three-ways (purchased put spreads and written call options). These derivative instruments either fix the price a party receives for its production or, in the case of option contracts, set a minimum price or a price within a fixed range.

Compression is the process of squeezing a given volume of gas into a smaller space.

Completion refers to the work performed and the installation of permanent equipment for the production of natural gas and crude oil from a recently drilled well.

Developed acreage is acreage that is allocated or assignable to producing wells or wells capable of production.

Development well is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Dry hole is an exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation is drilling wells in areas proven to be productive.

Exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

Fair-value hedges are derivative instruments used to hedge or offset the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment. For example, a contract is entered into whereby a commitment is made to deliver to a customer a specified quantity of crude oil or natural gas at a fixed price over a specified period of time. In order to hedge against changes in the fair value of these commitments, a party enters into swap agreements with financial counterparties that allow the party to receive market prices for the committed specified quantities included in the physical contract.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Formation is a stratum of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

Gross acres or gross wells are the total acres or wells in which a working interest is owned.

Horizon is a zone of a particular formation or that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.

Independent oil and gas company is a company that is primarily engaged in the exploration and production sector of the oil and gas business.

Infill drilling refers to drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

Lease operating or well operating expenses are expenses incurred to operate the wells and equipment on a producing lease.

Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by the Company's working interest percentage in the properties.

Oil and NGLs are converted into cubic feet of gas equivalent based on 6 MCF of gas to one barrel of oil or NGLs.

Operating costs include direct and indirect expenses, including divisional office expenses, incurred to manage, operate and maintain the Company's wells and related equipment and facilities.

Permeability is a measure of ease with which fluids can move through a reservoir.

Porosity is the ratio of the volume of empty space to the volume of solid rock in a formation, indicating how much fluid a rock can hold.

Production costs are costs incurred to operate and maintain the Company's wells and related equipment and facilities. These costs include well operating costs, severance taxes and ad valorem taxes.

Productive well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves are the portion of proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. For complete definitions of proved developed natural gas, NGLs and crude oil reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved reserves represent estimated quantities of natural gas, NGLs and crude oil which geological and engineering data demonstrate, with reasonable certainty, can be recovered in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests. For complete definitions of proved natural gas, NGLs and crude oil reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved undeveloped reserves are the portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion. For complete definitions of proved undeveloped natural gas, NGLs and crude oil reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Put options are contracts giving the holder (purchaser) the right, but not the obligation, to sell (put) a specified item at a fixed price (exercise or strike price) during a specified period. The purchaser pays a nonrefundable fee (the premium) to the seller (writer).

Reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock and water barriers and/or is individual and separate from other reservoirs.

Seismic is an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation. (2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional pictures.)

Sour gas is natural gas containing chemical impurities, notably hydrogen sulfide, other sulfur compounds and/or carbon dioxide.

Spacing is the number of wells which conservation laws allow to be drilled on a given area of land.

Step-out drilling is drilling a well adjacent to a proven well but moving in the direction of an unproven area.

Swaps are contracts between two parties to exchange streams of variable and fixed prices on specified notional amounts. One party to the swap pays a fixed price while the other pays a variable price.

Sweet gas is natural gas free of significant amounts of hydrogen sulfide or carbon dioxide when produced.

Tight gas is natural gas produced from a formation with low permeability that will not give up its gas readily at high flow rates.

Transportation expense primarily includes costs to process, including payments made in-kind, and costs to transport crude oil, NGLs and natural gas to a major facility, market hub, sales point or plant.

Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas.

Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is operations on a producing well to restore or increase production.

Writer refers to the seller of an option. The writer earns the premium on the option but bears the risk of fulfilling the obligations of the option.

Zone is a stratigraphic interval containing one or more reservoirs.

PART I

ITEMS ONE AND TWO

BUSINESS AND PROPERTIES

Burlington Resources Inc. ("BR") is among the world's largest independent oil and gas companies and holds one of the industry's leading positions in North American natural gas reserves and production. BR conducts exploration, production and development operations in the U.S., Canada, United Kingdom, Africa, China and South America. BR is a holding company and its principal subsidiaries include Burlington Resources Oil & Gas Company LP, The Louisiana Land and Exploration Company ("LL&E"), Burlington Resources Canada Ltd. (formerly known as Poco Petroleums Ltd.), Burlington Resources Canada (Hunter) Ltd. (formerly known as Canadian Hunter Exploration Ltd.) ("Hunter"), and their affiliated companies (collectively, "the Company").

During 2002, after announcing in late 2001 its intent to sell certain non-core, non-strategic properties, the Company sold approximately 1 TCFE of reserves and a processing facility. As a result of these property sales, the Company generated proceeds, before post-closing adjustments, of approximately $1.2 billion. The Company used a portion of the proceeds generated from property sales to retire debt and for general corporate purposes.

In December 2001, the Company consummated the acquisition of Hunter valued at approximately U.S. $2.1 billion, resulting in goodwill of approximately $793 million. The Hunter acquisition added a portfolio of properties, primarily located in the Western Canadian Sedimentary Basin, an area in which the Company already operated. The most significant of the assets is the Deep Basin, one of North America's largest natural gas fields.

The Company's reportable segments are U.S., Canada and International. For financial information related to the Company's reportable segments, see Note 17 of Notes to Consolidated Financial Statements. The Company's worldwide major operating areas are discussed below.

North America

The Company's asset base is dominated by North American natural gas properties. Its extensive North American lease holdings extend from the U.S. Gulf Coast to Northeast British Columbia and Northern Alberta in Canada. The Company's North American operations include a mix of production, development and exploration assets.

Year Ended December 31, 2004	Worldwide	U.S.	U.S.'s % of Worldwide	Canada	Canada's % of Worldwide
			($ In Millions)		
Oil and gas capital expenditures					
Development	$1,273	$544	43%	$639	50%
Exploration	286	87	30	159	56
Acquisitions—proved	85	81	95	4	5
Total oil and gas capital expenditures	$1,644	$712	43%	$802	49%
Production					
Natural gas (MMCF per day)	1,914	908	47%	819	43%
NGLs (MBbls per day)	65.3	41.7	64	23.6	36
Crude oil (MBbls per day)	85.2	37.2	44%	5.5	6%
December 31, 2004					
Proved reserves (TCFE)	12.0	8.0	67%	2.7	22%

U.S.

San Juan Basin

The San Juan Basin, in northwest New Mexico and southwest Colorado, is one of the Company's major operating areas in terms of reserves and production. The San Juan Basin encompasses nearly 7,500 square miles, or approximately 4.8 million acres, with the major portion located in New Mexico's Rio Arriba and San Juan counties. The Company is a significant holder of productive leasehold acreage in this area with over 840,000 net acres under its control. The Company operates almost 7,500 well completions in the San Juan Basin and holds interests in an additional 4,700 non-operated well completions.

In 2004, the Company invested $154 million in oil and gas capital, excluding acquisitions, drilled or participated in drilling 361 new wells and performed 172 workovers on existing wells. The Company's net production from the San Juan Basin averaged approximately 550 MMCF of natural gas per day, 31.3 MBbls of NGLs per day and 1.1 MBbls of crude oil per day during 2004. Production from the San Juan Basin grew significantly during the 1990s, first as a result of Fruitland Coal drilling and then as a result of development of tight gas formations. By the end of the decade, all formations were experiencing some decline; however, the Company has been able to maintain flat production for the last three years. To mitigate Fruitland Coal production decline, the Company has an ongoing program that consists of performing workovers on existing wells, adding compression, and installing artificial lift, where appropriate. The Company drilled or participated in drilling 200 wells on 320-acre and 160-acre spacing during 2004. In 2004, net production from the Fruitland Coal averaged 206 MMCF of natural gas per day from over 1,900 completions.

Also in 2004, the Company completed a $28 million purchase of 1,242 undrilled acres in Negro Canyon, which is located in the heart of the Company's Fruitland Coal producing area. The purchase encompasses a 100 percent working interest and 87.5 percent net revenue interest in the tract. Production has already been established and the Company expects to fully develop these leases by the end of 2006.

The three conventional formations (Mesaverde, Pictured Cliffs and Dakota) in the San Juan Basin continue to provide attractive development opportunities for the Company. The Mesaverde formation, which consists of the Lewis Shale, Cliffhouse, Menefee and Point Lookout sands, is the largest producing tight gas formation in the San Juan Basin. In 2004, the Company continued its ongoing infill-drilling program in this formation. In 2004, the Company drilled or participated in drilling 161 conventional wells on 160-acre and 80-acre spacing. Net production from the tight gas producing formations averaged 344 MMCF of natural gas per day, 31.3 MBbls of NGLs per day and 1.1 MBbls of crude oil per day in 2004.

Wind River Basin

The Madden Field, located in the Wind River Basin, covers more than 70,000 acres in Wyoming's Fremont and Natrona counties. Net production averaged 119 MMCF of natural gas per day in 2004 from multiple horizons ranging in depth from 5,000 feet to over 25,000 feet, where the deep Madison formation occurs. Investments in the Wind River Basin during 2004 totaled $24 million for 57 newly drilled wells and workover projects. The Company owns an approximate 48 percent working interest in the Lost Cabin Gas Plant and a 43 percent net revenue interest in the Madison reservoir.

Williston Basin

The Williston Basin operations, located in western North Dakota and eastern Montana, were focused on activities on the Cedar Creek Anticline and in the Bakken Shale formation during 2004. Total Williston Basin production averaged 21.2 MBbls of crude oil per day and 8 MMCF of natural gas per day. During 2004, the Company invested $113 million on projects in the Williston Basin.

The Company continued its highly active waterflood development program at both the Cedar Hills South and East Lookout Butte Units, where the focus has moved to 160-acre infill drilling. A total of 39 production and 8 injection wells were drilled in the two units, along with the continued expansion of the injection and gathering infrastructure. In addition to the development drilling program on the Cedar Creek Anticline, a new development area was initiated in Richland County, Montana, where the Company drilled 8 horizontal wells in the siltstone of the Bakken Shale formation and acquired additional acreage. The Company currently controls over 60,000 acres including areas in Richland County, Montana, and McKenzie County, North Dakota.

Anadarko Basin

The Anadarko Basin, located principally in western Oklahoma, encompasses over 30,000 square miles and contains some of the deepest producing formations in the world. The Company controls over 250,000 net acres and produces from multiple horizons ranging in depth from 11,000 feet to over 21,000 feet. Net production for 2004 from the Anadarko Basin averaged 70 MMCF of natural gas per day and 1.9 MBbls of NGLs per day. During 2004, the Company invested $31 million in the Anadarko Basin. Operated activity focused on the Red Fork formation in Roger Mills County, Oklahoma, where the Company drilled 14 wells.

Permian Basin

Permian Basin operations, in west Texas, are focused on the Waddell Ranch Field. Total Permian Basin production in 2004 averaged 14 MMCF of natural gas per day, 4.0 MBbls of crude oil per day and 2.0 MBbls of NGLs per day, with the Waddell Ranch Field contributing 10 MMCF of natural gas per day, 2.7 MBbls of crude oil per day and 2.0 MBbls of NGLs per day. During 2004, the Company invested $10 million in Permian Basin operations.

Fort Worth Basin

In the Fort Worth Basin of north central Texas, the Company is focused on the continued development of the Barnett Shale formation acreage position in Denton and Wise Counties, Texas. The Company employed up to five rigs during the year to drill or participate in 93 wells in the Barnett Shale formation, including an 11 well horizontal drilling program. The Company invested $83 million in 2004 with production averaging 33 MMCF of natural gas per day, 4.2 MBbls of NGLs per day and 1.0 MBbls of crude oil per day.

Onshore Gulf Coast Area

The Onshore Gulf Coast Area includes operations in a number of drilling trends in east Texas, south Louisiana, the Onshore Gulf of Mexico and the Florida panhandle. In south Louisiana, the Company owns 660,000 acres of fee lands with both surface and mineral rights. In early 2004, the Company acquired $70 million of properties in south Louisiana from ChevronTexaco. The Company spent $29 million of capital on these properties in 2004, and production increased to over 20 MMCF of natural gas per day. In the East Texas Bossier trend, the Company commenced drilling seven wells in 2004, and natural gas sales averaged 7 MMCF per day. Overall, the Company invested $138 million on 128 drilling, workover and facilities projects in the Gulf Coast Area. Net production for 2004 averaged 108 MMCF of natural gas per day, 9.2 MBbls of crude oil per day and 1.5 MBbls of NGLs per day.

Canada

Western Canadian Sedimentary Basin

In the Western Canadian Sedimentary Basin, the Company's portfolio of opportunities includes conventional exploration and development in Alberta, British Columbia and Saskatchewan.

Canadian activity in 2004 was focused on expanding activity into large-scale repeatable drilling programs in conventional and lower permeability reservoirs. Oil and gas capital investment in Canada was $798 million, excluding acquisitions, and 591 wells were drilled. Production in Canada was 819 MMCF of natural gas per day, 23.6 MBbls of NGLs per day and 5.5 MBbls of crude oil per day during 2004.

The Deep Basin area, in Alberta and British Columbia, consists of the Elmworth, Wapiti, Noel and Brassey Fields. In 2004, a $262 million oil and gas capital program was focused on exploration and development in the Deep Basin area. As a result, 106 wells were drilled and 231 MMCF of natural gas per day and 12.3 MBbls of NGLs per day were produced from this area.

In 2004, the Company completed resource assessment studies that identified future drilling opportunities across 4 horizons in the Deep Basin. The most prolific of these formations include the Cadomin, Falher-A, Falher-B and Cadotte. The Company also conducted down-spacing studies across the Cadomin, Chinook and Belly River horizons. These studies were supplemented by favorable regulatory approval to reduce well spacing from 640-acre to 320-acre over 55 sections of the Deep Basin.

In the Foothills area, which borders on the west side of the Deep Basin, oil and gas capital spending focused on exploration and development was $31 million and production was 53 MMCF of natural gas per day. Five wells were drilled in 2004.

The O'Chiese area in central Alberta yielded production of 161 MMCF of natural gas per day, 6.2 MBbls of NGLs per day and 2.0 MBbls of crude oil per day in 2004. The O'Chiese area was the focus of a $144 million exploration and development program in 2004 that mostly targeted the Lower Cretaceous and Jurassic sands, the principal historical targets. In 2004, 111 wells were drilled.

In the Northern Plains, the Company continued exploration and development activities in the northern Alberta and British Columbia areas. Production in this area during 2004 averaged 83 MMCF of natural gas per day and 2.0 MBbls of NGLs per day. A capital program in this area of $83 million targeted the Bluesky, Gething and Montney formations and 58 wells were drilled during 2004.

In the Kaybob area, production for the year averaged 112 MMCF of natural gas per day, 1.8 MBbls of NGLs per day and 0.8 MBbls of crude oil per day. The Company invested $170 million and 82 wells were drilled during 2004.

The Southern Plains area, which includes the Viking Kinsella property, produced approximately 166 MMCF of natural gas per day, 1.4 MBbls of crude oil per day and 1.2 MBbls of NGLs per day in 2004. In 2004, the Company invested $81 million and 214 wells were drilled in the Southern Plains area.

In 2004, the Company divested its acreage position in the Mackenzie Delta area to focus efforts on Western Canadian Sedimentary Basin opportunities.

International

The Company's International operations include a combination of exploration opportunities, large field development projects, and production operations. Key focus areas are Northwest Europe, North Africa, China, and South America.

Year Ended December 31, 2004	Worldwide	International	% of Worldwide
		($ In Millions)	
Oil and gas capital expenditures			
Development	$1,273	$ 90	7%
Exploration	286	40	14
Acquisitions—proved	85	—	—
Total oil and gas capital expenditures	$1,644	$130	8%
Production			
Natural gas (MMCF per day)	1,914	187	10%
NGLs (MBbls per day)	65.3	—	—
Crude oil (MBbls per day)	85.2	42.5	50%
December 31, 2004			
Proved reserves (TCFE)	12.0	1.3	11%

Northwest Europe

The East Irish Sea assets consist of eight licenses covering 163,000 acres. The Company has a 100 percent working interest in seven operated gas fields. First production from two sweet gas fields, Millom and Dalton, commenced in 1999. Net production from the East Irish Sea averaged 87 MMCF of natural gas per day during 2004. The Company invested $53 million of capital in this area during the year.

The development of the sour gas fields in the East Irish Sea continued with first production from Calder in October 2004, representing the first development in the Rivers Fields. Operational issues identified during the startup phase of the Rivers Fields onshore gas processing terminal resulted in the shut down of production from mid-November through the remainder of the year. Production at the Rivers Fields is expected to resume by the second quarter of 2005 and is expected to peak at a sales rate of approximately 100 MMCF of natural gas per day during the year.

The Company's remaining Northwest European shelf operations consist of non-operated production from the Company's wholly-owned Netherlands affiliate ("CLAM") in the Dutch sector of the North Sea. The CLAM assets yielded an annual production rate of 72 MMCF of natural gas per day in 2004.

North Africa

In North Africa, the Company continued with its exploration and development programs in both Algeria and Egypt. The Company benefited from a full year's production from Algeria Block 405a. Plans for future developments were advanced in both Algeria and Egypt, and the Company completed its exploration program on Algeria Block 402d. The Company's capital investments in North Africa during 2004 totaled $33 million.

In Algeria, at the Menzel Lejmat North (MLN) Field on Block 405a, where the Company has a 65 percent working interest, activity was primarily focused on stabilizing production from the Company-operated MLN central processing facility. Annual average net oil production was 11.0 MBbls of crude oil per day. One natural gas injection well was successfully drilled and completed during 2004 for reservoir pressure maintenance purposes. In the MLSE area, on the southern portion of the block, development plans for crude oil and natural gas discoveries are being discussed with Sonatrach, the Algerian national oil company.

The Ourhoud Field, in which the Company has a 3.7 percent working interest, produced at an average net rate of 5.5 MBbls of crude oil per day. Five development wells, four injection wells and one water-source well were drilled during 2004, and the waterflood development of this large crude oil field was continued. The Company relinquished its 75 percent working interest in Block 402d in December of 2004.

In Egypt, where the Company has a 50 percent non-operated working interest in the Offshore North Sinai permit, development of the Company's gas discoveries progressed. An agreement was reached with the Egyptian authorities on a revision to the existing gas sales contract to revise the start date of the project and to bring the pricing structure in line with other Egyptian contracts of this nature. Also, engineering design studies were begun to determine the facilities required to develop the Tao Field and potential satellites. These studies should be completed in 2005.

China

In the Far East, the Company continued its focus on selected basins in China. In 2004, an offshore oil development project achieved the first full year of production and the first phase of a development plan for an onshore gas development received sanctioning and is working toward long-term expansion. The Company invested $42 million in China in 2004.

During the year, the initial development drilling program was completed for the Panyu offshore oil project in the Pearl River Mouth Basin of the South China Sea. The Panyu development involves two offshore oil fields, Bootes and Ursa, located in Block 15/34, in which the Company holds a 24.5 percent working interest. First production was achieved in October 2003, and in 2004 the initial development drilling program was successfully completed. In 2004, the average net production was 19.0 MBbls of crude oil per day.

The Company holds a 100 percent working interest in a natural gas project in the onshore Chuanzhong Block in the Sichuan Basin. In 2004, the Company received government sanctioning of the first phase of development. The project represents an opportunity to apply the Company's expertise in the development of tight gas reservoirs in an area with substantial reserve potential. During 2004, net production in this area was 5 MMCF of natural gas per day.

South America

The Company's efforts in South America during 2004 focused on expanding near-term production potential and enhancing long-term exploration opportunities. Net production from South America averaged 6.8 MBbls of crude oil per day and 23 MMCF of natural gas per day. The Company invested $18 million of capital in South America during the year.

In Ecuador, the Company holds a 30 percent working interest in Block 7 and a 37.5 percent working interest in Block 21. Phase II development of the Yuralpa Field in Block 21 is underway following startup in December 2003. Production in this area averaged 4.0 MBbls of crude oil per day during 2004. In Block 7, four wells were successfully drilled during 2004. Net production in Block 7 for the year was 2.6 MBbls of crude oil per day. In Ecuador, the Company's capital investments in 2004 totaled $12 million.

In Argentina, the Company holds a 25.7 percent working interest in the Sierra Chata concession in the Neuquen Basin. The Company's net production averaged 23 MMCF of natural gas per day in 2004.

In Peru, the Company entered into an agreement to acquire a 23.9 percent working interest in Block 57, located in the Ucayali Basin. The Company also holds a 23.9 percent working interest in Block 90. In the Marañon Basin, the Company entered into an agreement to farm-in a 45 percent working interest in Block 39 and signed a preliminary agreement to explore and operate Block 104 with a 100 percent working interest. During early 2004, the Company relinquished its interests in Block 87.

In Colombia, the Company holds an exploration contract for a 100 percent working interest in the Orquídea area of the Middle Magdalena Basin. A 3-D seismic acquisition program was completed in November 2004.

Productive Wells

Working interests in productive wells follow.

Year Ended December 31, 2004	Gross	Net
North America		
U.S.		
Natural gas	11,533	6,609
Crude oil	2,722	1,313
Canada		
Natural gas	5,768	4,458
Crude oil	1,147	581
International		
Natural gas	198	62
Crude oil	166	46
Worldwide		
Natural gas	17,499	11,129
Crude oil	4,035	1,940
Total Worldwide	21,534	13,069

Net Wells Drilled

The following table sets forth the Company's net productive and dry wells.

Year Ended December 31,	2004	2003	2002
North America			
U.S.			
Productive			
Exploratory	3.9	0.9	4.5
Development	331.3	399.0	158.6
Dry			
Exploratory	4.5	2.5	6.3
Development	4.0	5.3	2.1
Total U.S.	343.7	407.7	171.5
Canada			
Productive			
Exploratory	32.6	102.5	73.3
Development	395.4	384.4	320.8
Dry			
Exploratory	25.0	48.6	44.7
Development	27.2	57.6	46.2
Total Canada	480.2	593.1	485.0
International			
Productive			
Exploratory	2.0	0.7	0.1
Development	8.5	10.9	1.5
Dry			
Exploratory	3.1	1.8	2.0
Development	—	1.0	0.1
Total International	13.6	14.4	3.7
Worldwide			
Productive			
Exploratory	38.5	104.1	77.9
Development	735.2	794.3	480.9
Dry			
Exploratory	32.6	52.9	53.0
Development	31.2	63.9	48.4
Total Worldwide	837.5	1,015.2	660.2

As of December 31, 2004, 331 gross wells, representing approximately 227 net wells, were being drilled or awaiting completion with 71 percent and 29 percent of these wells located in Canada and the U.S., respectively.

Acreage

Working interests in developed and undeveloped acreage follow.

December 31, 2004	Gross	Net
North America		
U.S.		
Developed Acreage	4,576,365	2,591,740
Undeveloped Acreage	9,524,272	7,961,776
Canada		
Developed Acreage	3,422,463	2,301,943
Undeveloped Acreage	5,124,634	3,410,447
International		
Developed Acreage	690,813	209,650
Undeveloped Acreage	11,261,232	5,188,363
Worldwide		
Developed Acreage	8,689,641	5,103,333
Undeveloped Acreage	25,910,138	16,560,586
Total Worldwide	34,599,779	21,663,919

Capital Expenditures

The Company's capital expenditures follow.

Year Ended December 31,	2004	2003	2002
		(In Millions)	
North America			
U.S.			
Oil and Gas Activities	$ 712	$ 540	$ 463
Plants and Pipelines	3	5	28
Administrative and Other	24	23	35
Total U.S.	739	568	526
Canada			
Oil and Gas Activities	802	679	839
Plants and Pipelines	31	19	29
Administrative and Other	9	17	8
Total Canada	842	715	876
International			
Oil and Gas Activities	130	366	299
Plants and Pipelines	32	139	136
Administrative and Other	4	—	—
Total International	166	505	435
Worldwide			
Oil and Gas Activities	1,644	1,585	1,601
Plants and Pipelines	66	163	193
Administrative and Other	37	40	43
Total Worldwide	$1,747	$1,788	$1,837

In 2004, worldwide capital expenditures related to oil and gas activities were $1,644 million and included 78 percent associated with development, 17 percent for exploration and 5 percent for proved property acquisitions. Exploration costs expensed under the successful efforts method of accounting are included in capital expenditures for oil and gas activities.

Oil and Gas Production and Prices

The Company's average daily production represents its net ownership and includes royalty interests and net profit interests owned by the Company. The Company's average daily production and average sales prices follow.

Year Ended December 31,	2004	2003	2002
North America			
U.S.			
Production			
Natural gas (MMCF per day)	908	865	949
NGLs (MBbls per day)	41.7	37.4	32.7
Crude oil (MBbls per day)	37.2	29.3	35.4
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 5.54	$ 4.87	$ 3.39
Natural gas, (gain) loss on hedging (per MCF)	(0.02)	0.10	(0.25)
Natural gas, excluding hedging (per MCF)	5.52	4.97	3.14
NGLs (per Bbl)	22.87	18.42	13.23
Crude oil, including hedging (per Bbl)	36.31	28.08	23.16
Crude oil, (gain) loss on hedging (per Bbl)	2.28	0.14	(0.24)
Crude oil, excluding hedging (per Bbl)	$38.59	$28.22	$22.92
Canada			
Production			
Natural gas (MMCF per day)	819	867	802
NGLs (MBbls per day)	23.6	27.4	27.4
Crude oil (MBbls per day)	5.5	5.1	7.8
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 5.85	$ 5.12	$ 3.17
Natural gas, (gain) loss on hedging (per MCF)	0.05	0.10	(0.06)
Natural gas, excluding hedging (per MCF)	5.90	5.22	3.11
NGLs (per Bbl)	29.79	23.08	15.92
Crude oil (per Bbl)	$37.70	$31.11	$28.32
International			
Production			
Natural gas (MMCF per day)	187	167	165
Crude oil (MBbls per day)	42.5	12.1	5.9
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 3.64	$ 3.07	$ 2.27
Natural gas, gain on hedging (per MCF)	—	—	(0.08)
Natural gas, excluding hedging (per MCF)	3.64	3.07	2.19
Crude oil (per Bbl)	$35.94	$23.49	$24.30
Worldwide			
Production			
Natural gas (MMCF per day)	1,914	1,899	1,916
NGLs (MBbls per day)	65.3	64.8	60.1
Crude oil (MBbls per day)	85.2	46.5	49.1
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 5.49	$ 4.83	$ 3.20
Natural gas, (gain) loss on hedging (per MCF)	0.01	0.09	(0.16)
Natural gas, excluding hedging (per MCF)	5.50	4.92	3.04
NGLs (per Bbl)	25.38	20.40	14.46
Crude oil, including hedging (per Bbl)	36.25	27.22	24.11
Crude oil, (gain) loss on hedging (per Bbl)	0.99	0.09	(0.18)
Crude oil, excluding hedging (per Bbl)	$37.24	$27.31	$23.93

Production Unit Costs

The Company's production unit costs follow. Production costs include production taxes and well operating costs.

Year Ended December 31,	2004	2003	2002
		(Per MCFE)	
North America			
U.S.			
Average Production Costs	$0.80	$0.68	$0.62
DD&A Rates	0.68	0.62	0.66
Canada			
Average Production Costs	0.55	0.44	0.38
DD&A Rates	1.41	1.19	0.97
International			
Average Production Costs	0.60	0.53	0.32
DD&A Rates	1.32	1.14	1.02
Worldwide			
Average Production Costs	0.68	0.57	0.50
DD&A Rates	$1.04	$0.91	$0.81

Reserves

The following table sets forth estimates by the Company's petroleum engineers of proved natural gas, NGLs and crude oil reserves at December 31, 2004. These reserves have been prepared in accordance with the Securities and Exchange Commission's Regulations. These reserves have been reduced for royalty interests owned by others.

December 31, 2004	Proved Developed	Proved Undeveloped	Total Proved Reserves
North America			
U.S.			
Natural gas (BCF)	3,745	1,331	5,076
NGLs (MMBbls)	193.1	85.3	278.4
Crude oil (MMBbls)	185.8	18.7	204.5
Total U.S. (BCFE)	6,019	1,954	7,973
Canada			
Natural gas (BCF)	1,821	509	2,330
NGLs (MMBbls)	44.6	9.5	54.1
Crude oil (MMBbls)	13.6	4.3	17.9
Total Canada (BCFE)	2,170	592	2,762
International			
Natural gas (BCF)	435	385	820
Crude oil (MMBbls)	48.5	26.8	75.3
Total International (BCFE)	726	546	1,272
Worldwide			
Natural gas (BCF)	6,001	2,225	8,226
NGLs (MMBbls)	237.7	94.8	332.5
Crude oil (MMBbls)	247.9	49.8	297.7
Total Worldwide (BCFE)	8,915	3,092	12,007

Miller and Lents, Ltd. and Sproule Associates Limited, independent oil and gas consultants, have reviewed the estimates of proved reserves of natural gas, crude oil and NGLs that the Company attributed to its net interests in oil and gas properties as of December 31, 2004. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and International interests and Sproule Associates Limited reviewed the Company's interests in Canada. Based on their review of more than 80 percent of the Company's reserve estimates, it is their judgment that the estimates are reasonable in the aggregate. For more information, see independent oil and gas consultants letters on pages 69-73.

For further information on reserves, including information on future net cash flows and the standardized measure of discounted future net cash flows, see "Supplementary Financial Information—Supplemental Oil and Gas Disclosures."

Other Matters

Competition—The Company actively competes for reserve acquisitions, exploration leases and sales of natural gas and crude oil, frequently against companies with substantially larger financial and other resources. In its marketing activities, the Company competes with numerous companies for the sale of natural gas, NGLs and crude oil. Competitive factors in the Company's business include price, contract terms, quality of service, pipeline access, transportation discounts and distribution efficiencies.

Regulation of Oil and Gas Production, Sales and Transportation—The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments throughout the world. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which the Company operates also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

The Company operates various gathering systems. The United States Department of Transportation and certain governmental agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities by prescribing standards. However, based on current standards concerning transportation and storage activities and any proposed or contemplated standards, the Company believes that the impact of such standards is not material to the Company's operations, capital expenditures or financial position. Compliance with such standards has been incorporated by the Company in its operations over many years and no material capital expenditures are allocated to such compliance.

All of the Company's sales of its domestic natural gas are currently deregulated, although governmental agencies may elect in the future to regulate certain sales.

Environmental Regulation—Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect the Company's domestic exploration, development and production operations and the costs of those operations. In addition, the Company's international operations are subject to environmental regulations administered by foreign governments, including political subdivisions thereof, or by international organizations. These domestic and international laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance under the Oil Pollution Act of 1990 and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from the Company's operations and may require the suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to the Company and its operations include, among others, the following United States federal laws and regulations:

- Clean Air Act, and its amendments, which governs air emissions;
- Clean Water Act, which governs discharges to waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as "Super Fund");
- Resource Conservation and Recovery Act, which governs the management of solid waste;
- Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;
- Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

In addition, many states and foreign countries where the Company operates have similar environmental laws and regulations covering the same types of matters. In Canada, environmental compliance is governed by various statutes, regulations and codes promulgated at different levels of government including the federal Fisheries Act and Canadian Environmental Protection Act; and provincially, the Environmental Protection and Enhancement Act, the Oil and Gas Conservation Act and the Pipeline Act in the province of Alberta; and the Waste Management Act, the Environmental Assessment Act and the Environment Management Act in the province of British Columbia. The Kyoto Protocol to the United Nations Framework Convention on Climate Change ("Kyoto Protocol") became effective February 16, 2005, and requires Annex I countries, including Canada and the United Kingdom, to reduce their emissions of carbon dioxide and other greenhouse gases. As a result of the ratification of the Kyoto Protocol and the adoption of legislation or other regulatory initiatives designed to implement its objectives by the national and regional governments, reductions in greenhouse gases from crude oil and natural gas producers may be required which could result in, among other things, increased operating and capital expenditures for those producers. Until such legislation or other regulatory initiatives are finalized, the impact of the Kyoto Protocol and any such legislation adopted as a result of its ratification remains uncertain.

The Company routinely obtains permits for its facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of the Company's facilities or operations.

The ultimate financial impact of these environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on the Company's operations in the United States and in most countries in which it operates. In addition, any non-compliance with such laws could subject the Company to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of the Company's ongoing operations and not an extraordinary cost of compliance with government regulations.

The Company is committed to the protection of the environment throughout its operations and believes that it is in substantial compliance with applicable environmental laws and regulations. The Company believes that environmental stewardship is an important part of its daily business and will continue to make expenditures on a regular basis relating to environmental compliance. The Company maintains insurance coverage for spills, pollution and certain other environmental risks, although it is not fully insured against all such risks. The insurance coverage maintained by the Company provides for the reimbursement to the Company of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of the Company's operations, but such insurance does not fully insure pollution and similar environmental risks. The Company does not anticipate that it will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on the consolidated financial position or results of operations of the Company. However, since environmental costs and liabilities are inherent in the Company's operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Filings of Reserve Estimates With Other Agencies—During 2004, the Company filed estimates of its oil and gas reserves for the year 2003 with the Department of Energy. These estimates differ by 5 percent or less from the reserve data presented. For information concerning proved natural gas, NGLs and crude oil reserves, see "Supplementary Financial Information—Supplemental Oil and Gas Disclosures."

Employees

The Company had 2,214 and 2,111 employees at December 31, 2004 and 2003, respectively. At December 31, 2004, the Company had no union employees.

Web Site Access to Reports

The Company's Web site address is **www.br-inc.com**. The Company makes available, free of charge on or through its Web site, its annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission. Such reports, which include the Company's annual and quarterly financial statements, are also filed in Canada on the System for Electronic Document Analysis and Retrieval (SEDAR) and are also available to the Company's stockholders, including those residing in Ontario, Canada, from the Company upon request at no charge.

ITEM THREE

LEGAL PROCEEDINGS

See Note 14 of Notes to Consolidated Financial Statements.

ITEM FOUR

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Burlington Resources Inc.'s security holders during the fourth quarter of 2004.

EXECUTIVE OFFICERS OF THE REGISTRANT

Bobby S. Shackouls, 54—Chairman of the Board, President and Chief Executive Officer, Burlington Resources Inc., July 1997 to present.

Randy L. Limbacher, 46—Office of the Chairman, Burlington Resources Inc., January 2004 to present. Executive Vice President and Chief Operating Officer, Burlington Resources Inc., December 2002 to present. Senior Vice President, Production, Burlington Resources Inc., April 2001 to December 2002. President and Chief Executive Officer, BROG GP Inc., general partner of Burlington Resources Oil & Gas Company LP, December 2000 to July 2001. President and Chief Executive Officer, Burlington Resources Oil & Gas Company, July 1998 to December 2000.

Steven J. Shapiro, 52—Office of the Chairman, Burlington Resources Inc., January 2004 to present. Executive Vice President and Chief Financial Officer, Burlington Resources Inc., December 2002 to present. Senior Vice President and Chief Financial Officer, Burlington Resources Inc., October 2000 to December 2002. Senior Vice President, Chief Financial Officer and Director, Vastar Resources, Inc., 1993 to September 2000.

Mark E. Ellis, 48—Senior Vice President, North American Production, Burlington Resources Inc., September 2004 to present. President, Burlington Resources Canada Ltd., October 2000 to September 2004. Vice President, San Juan Division, Burlington Resources Oil & Gas Company, January 1997 to October 2000.

L. David Hanower, 45—Senior Vice President, Law and Administration, Burlington Resources Inc., July 1998 to present.

John A. Williams, 60—Senior Vice President, Exploration, Burlington Resources Inc., April 2001 to present. Senior Vice President, Exploration, BROG GP Inc., general partner of Burlington Resources Oil & Gas Company LP, December 2000 to present. Senior Vice President, Exploration, Burlington Resources Oil & Gas Company, July 1998 to December 2000.

PART II

ITEM FIVE

MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock, par value $.01 per share ("Common Stock"), is traded on the New York Stock Exchange under the symbol "BR." Effective at the close of business on January 31, 2005, the Company discontinued the listing of its Common Stock on the Toronto Stock Exchange. At December 31, 2004, the number of record holders of Common Stock was 11,801. Information on Common Stock prices and quarterly dividends is shown on page 79 under the subheading "Quarterly Financial Data—Unaudited." See also "Equity Compensation Plan Information" under Part III, Item 12 of this report.

Issuer Purchases of Equity Securities (1)

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
		(In Thousands, Except per Share Amounts)		
October 1, 2004 – October 31, 2004	1,363	$41.73	1,363	$359,818
November 1, 2004 – November 30, 2004	1,365	42.39	1,365	301,959
December 1, 2004 – December 31, 2004	1,430	43.31	1,430	$952,229
Total	4,158	$42.49	4,158	

(1) In December 2000, the Company announced that the Board of Directors ("Board") authorized the repurchase of up to $1 billion of the Company's Common Stock. Through April 30, 2003, the Company had repurchased $816 million of its Common Stock under the program authorized in December 2000. In April 2003, the Company announced that the Board voted to restore the authorization level to $1 billion effective May 1, 2003. Through December 7, 2004, the Company had repurchased $712 million of its Common Stock under the program authorized in April 2003. In December 2004, the Company announced that the Board again voted to restore the authorization level to $1 billion.

SELECTED FINANCIAL DATA

The selected financial data for the Company set forth below should be read in conjunction with the consolidated financial statements and accompanying notes thereto.

Year Ended December 31,	**2004**	**2003**	**2002**	**2001**	**2000**
	(In Millions, Except per Share Amounts)				
INCOME STATEMENT DATA					
Revenues	$ 5,618	$ 4,311	$ 2,968	$ 3,419	$3,218
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	2,304	1,570	569	907	967
Cumulative Effect of Change in Accounting Principle— Net	—	(59)	—	3	—
Net Income (1)	1,527	1,201	454	561	675
Basic Earnings per Common Share (1) (2) (3)	3.90	3.02	1.13	1.35	1.57
Diluted Earnings per Common Share (1) (2) (3)	3.86	3.00	1.13	1.35	1.56
Cash Dividends Declared per Common Share (3)	$ 0.32	$ 0.29	$ 0.28	$ 0.28	$ 0.28
December 31,					
BALANCE SHEET DATA					
Total Assets	$15,744	$12,995	$10,645	$10,582	$7,506
Long-term Debt	3,887	3,873	3,853	4,337	2,301
Stockholders' Equity	$ 7,011	$ 5,521	$ 3,832	$ 3,525	$3,750
Common Shares Outstanding (3)	388	395	403	402	431

(1) Year 2004 includes an income tax benefit of $23 million or $0.06 per share related to the reduction of the Canadian federal income tax rate and $45 million or $0.11 per share related to the reduction of the Alberta provincial income tax rate. In 2004, the Company recorded a U.S. income tax expense of $26 million or $0.07 per share related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004. Year 2004 also includes a non-cash after tax charge of $59 million ($90 million pretax) or $0.15 per share related to the impairment of undeveloped properties in Canada. Year 2003 includes an income tax benefit of $203 million or $0.51 per share related to the reduction of the Canadian federal income tax rate and $11 million or $0.02 per share related to the reduction of the Alberta provincial income tax rate. Year 2003 also includes a non-cash after tax charge of $38 million ($63 million pretax) or $0.09 per share related to the impairment of oil and gas properties in Canada.

(2) Year 2003 includes a cumulative effect of change in accounting principle ("Cumulative Effect") loss of $0.15 related to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, *Asset Retirement Obligations*. Year 2001 includes a Cumulative Effect gain of $0.01 related to the adoption of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

(3) Share amounts related to years 2000 through 2003 have been retroactively adjusted to reflect the 2-for-1 stock split of the Company's Common Stock effective June 1, 2004.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview

The Company is one of the largest independent exploration and production companies in North America. The Company explores for, develops and produces natural gas, NGLs and crude oil, primarily from its properties located in the Rocky Mountain natural gas fairway of North America, complemented by international operations. The Company's North American activities are concentrated in areas with known hydrocarbon resources, which are conducive to large, multi-well, repeatable drilling programs and the Company's technical skills. Internationally, the Company is focused on achieving operational efficiencies, while advancing potential growth opportunities in existing positions.

Basin Excellence[SM] is the Company's concept of concentrating its operations and expertise in core areas where it believes it holds significant competitive advantages. These areas are typically in high potential geologic basins with large natural gas and crude oil resources that support multiple-year development programs. These are also areas where the Company holds significant land or mineral interest positions, has teams with years of relevant geologic, geophysical, engineering and operational experience, has access to production, processing and gathering infrastructure and has long-term relationships with partners, suppliers and land and mineral interest owners. The Company believes that it has attained or will ultimately attain this stature in several areas throughout the world that currently represent the majority of its core assets. These assets traditionally yield high returns on investment, and, therefore, the Company has concentrated its activities in these areas and exited other areas that did not meet these standards.

The Company has adopted a disciplined capital allocation process, with the objective of achieving annual volumetric growth (in the range of three to eight percent as a long-term annual average) coupled with strong financial returns.

In managing its business, the Company must deal with numerous risks and uncertainties. These risks and uncertainties can be broadly categorized as: "subsurface," which includes the presence, size and recoverability of hydrocarbons; "regulatory," which includes access and permitting necessary to conduct its operations; "operational," which includes logistical, timing and infrastructure issues, especially internationally, which are often beyond the Company's control; and "commercial," which includes commodity price volatility, local price differentials in its various areas of operations and attention to operating margins and the availability of markets for its production, especially natural gas. Each of these factors is challenging and highly variable.

To address subsurface risks, the Company utilizes many of the latest technological tools available to assess and mitigate these risks. These tools include, but are not limited to, modern geophysical data and interpretation software, petrophysical information, physical core data, production histories, paleontology data and satellite imagery. In spite of these technologies, the multitude of unknown variables that exist below the surface of the earth make it difficult to consistently and accurately predict drilling results. The Company has put considerable emphasis in recent years on creating an asset portfolio that improves the reliability of those predictions; however, these types of operations tend to exploit or develop smaller quantities of hydrocarbon reserves and, as a result, the Company must develop more of these opportunities in order to maintain production. Similarly, the Company has reduced its focus on areas where there is far less analytical data available and drilling outcomes are less predictable, such as wildcat exploration operations in sparsely explored areas. The Company is constantly assessing its drilling opportunities to achieve balance in its drilling program for risk and financial returns. In order to make this possible, the Company attempts to maintain a large inventory of drillable projects from which its technical and management teams can select a drilling program in any given period.

On regulatory and operational matters, the Company actively manages its exploration and production activities. The Company values sound stewardship and strong relationships with all stakeholders in conducting its business. The Company attempts to stay abreast of emerging issues to effectively anticipate and manage potential impacts to the Company's operations.

Managing the commercial risks is an ongoing priority at the Company. Considerable analysis of historical price trends, supply statistics, demand projections and infrastructure constraints form the basis of the Company's outlook for the commodity prices it may receive for its future production. Because much of this data is dynamic, the Company's view and the market's view of future commodity pricing can change rapidly. Based on the Company's ongoing assessment of the underlying data and the markets, the Company will from time to time use various financial tools to hedge the price it will receive for a particular commodity in the future. The primary purpose of these activities is to enhance financial returns on the significant investments that the Company makes annually to replenish its productive base and grow its reserves while leaving as much commodity price upside as possible for the Company's stockholders. Margin enhancement is another important element of the Company's business, including attention to operating costs, administrative expenses and marketing activities, such as securing transportation to alternative market hubs to protect against weak producing-area prices. The Company may also enter into transportation agreements that allow the Company to sell a portion of its production in alternative markets when local prices are weak.

All of the risks and uncertainties described above create opportunities in the exploration and production business to the extent they drive the relative valuations of three distinct asset classes in the business. The first asset class is the commodities themselves—natural gas, NGLs and crude oil. The prices for this asset class are generally established by the purchasers of these commodities, but closely track the prices that are set through the public trading of futures contracts for those same commodities. The second asset class consists of the physical oil and gas properties that may contain proved, probable and possible reserves, as well as exploratory potential. The value of physical assets is usually established in a private market created by a willing seller and a willing buyer of a given property or group of properties. The third asset class consists of the equities of the publicly traded exploration and production companies that are valued in the public market place daily. Because these three asset classes are not always valued consistently with one another, opportunities may exist from time to time to take advantage of these various valuation differences. These valuation differences are key to the Company's capital allocation philosophy.

There are three types of investment alternatives that constantly compete for available capital at the Company. These include drilling opportunities, acquisition opportunities and financial alternatives such as share repurchases, dividends and debt repayment. Depending on circumstances and the relative valuations of the asset classes described above, the Company allocates capital among its investment alternatives through an allocation approach that is rate-of-return based. Its goal is to ensure that capital is being invested in the highest return opportunities available at any given time.

Much of what has been described above is conducted and handled routinely. The ability of the Company's management and staff to take into account all relevant factors, which fluctuate constantly, will be a key determinant in the Company's future performance.

Outlook

The Company's business model strives to achieve both production growth and sector-leading financial returns when compared to other independent oil and gas exploration and production companies. This model requires the continuous development of natural gas and crude oil reserves to fuel growth, while maintaining a rigorous focus on cost structure and capital efficiency.

Key to achieving the Company's financial goals is its disciplined capital investment approach. The Company deploys the net operating cash flows it generates among its core capital programs, as well as for acquisitions and other financial uses, such as share repurchases and dividend payments. Although commodity prices are volatile, the Company generally does not favor increasing or decreasing its capital program in response to commodity prices. Instead, the Company seeks to exercise a disciplined approach in order to keep its cost structure as low as possible.

The Company expects to continue focusing on exploring for and producing North American natural gas as its primary business. The Company expects North America to represent 85 percent of its total production in 2005. While the Company's management recognizes that the North American natural gas business has many characteristics of a mature, slow-growth business, it believes that finding or acquiring and producing North American natural gas will continue to be a profitable, high-return business for the Company due to certain unique advantages that position it to be successful. First, the Company has long-lived asset positions in gas resource-prone basins and focuses heavily on maintaining a competitive cost structure. Secondly, the Company executes a consistent capital program by employing a capital allocation approach that favors discipline and balance.

The Company's International business segment is less mature, but has undergone a significant growth phase after several years of developing major projects. The International segment is expected to represent 15 percent of the Company's total production in 2005 and remain at about that level for the foreseeable future.

Reserve Replacement

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to the Company's long-term success. Given the inherent decline of hydrocarbon reserves resulting from the production of those reserves, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined below, as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. The reserve replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries, and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table on pages 76-77 in the Supplementary Financial Information section of this report. Accordingly, the Company does not use unproved reserve quantities or proved reserve additions that include both proved reserve additions attributable to consolidated entities and investments accounted for using the equity method in calculating its reserve replacement ratio. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

It is also important for an exploration and production company to demonstrate a long-term trend of adding reserves at a reasonable cost. Given that the cost of adding reserves is ultimately included in depreciation, depletion and amortization ("DD&A") expense, management believes that an ability to add reserves in its core asset areas at a lower cost than its competition should contribute to a sustainable competitive advantage. The Company, in fact, has a goal to achieve 10 to 15 percent lower replacement costs than its competition in North America. Management therefore uses a per unit reserve replacement costs metric, as defined below, as an indicator of the Company's ability to replenish annual production volumes and grow reserves on a cost-effective basis. Analysts and investors use the measure widely and often cite the measure on a single year basis. In 2004, the Company's reserve replacement costs were $1.27 per MCFE including acquisitions or $1.27 per MCFE excluding acquisitions. The increase in costs was primarily due to industry service inflation. The Company typically cites reserve replacement costs in the context of a multi-year trend, in recognition of its limitations as a single year measure, but also to demonstrate consistency and stability, which are essential to the Company's business model. For the three-year period ended December 31, 2004, the Company's average reserve replacement costs were $1.17 per MCFE including acquisitions and $1.19 per MCFE excluding acquisitions. As used herein, reserve replacement costs represent total oil and gas capital costs, including acquisitions, incurred in order to add reserves. Reserve replacement costs per unit are calculated by dividing total oil and gas capital costs, including acquisitions, by the sum of reserve revisions, extensions, discoveries and other additions and acquisitions. The costs used to calculate reserve replacement costs include the costs of development, exploration and property acquisition activities as presented in the Supplemental Oil and Gas Disclosures table on page 74 of this report.

Set forth below are the Company's reserve replacement ratio and reserve replacement costs per unit, along with the Company's capital expenditures.

Year Ended December 31,	**2004**	**2003**	**2002**
		($ per MCFE)	
Reserve replacement costs, including acquisitions	$1.27	$1.19	$1.06
Reserve replacement costs, excluding acquisitions	$1.27	$1.23	$1.03
		(% of Production)	
Reserve replacement ratio, including acquisitions	125%	142%	161%
Reserve replacement ratio, excluding acquisitions	119%	118%	103%

Capital Expenditures

Year Ended December 31,	**2004**	**2003**	**2002**
		(In Millions)	
Total capital expenditures	$1,747	$1,788	$1,837
Less: acquisitions	85	228	604
Capital expenditures, excluding acquisitions	**$1,662**	**$1,560**	**$1,233**

The Company's focus on Basin Excellence℠ in established, long-lived core assets results in the majority of its reserve additions coming from development drilling, including extensions from both infill and step-out drilling. Resource assessment studies in targeted areas also result in the addition of proved undeveloped reserves at infill locations in existing producing fields. Reserves added include both proved developed and proved undeveloped components for all periods presented. Over the past two years, the ratio of proved undeveloped reserves to total proved reserves has been about 26 percent. Proved developed reserves will generally begin producing within the year they are added. Proved undeveloped reserves generally require a major future expenditure and it is anticipated that approximately 75 percent of these reserves will begin producing within five years from the date in which the reserves are recorded. Due to the Company's extensive inventory of potential capital projects, reserve additions are expected to continue in the future, particularly in the Company's core operating areas, although there are no assurances as to the timing and magnitude of these additions.

In 2005, the Company expects to spend approximately $2 billion of capital, excluding acquisitions. This level of spending represents a 21 percent increase over 2004 capital. The Company currently believes that this level of spending is needed in each of the next few years to achieve its objective of three to eight percent average annual production growth. Approximately 88 percent of the Company's 2005 capital program is allocated to its North American programs in Canada and the U.S. This capital level in North America represents an increase of approximately 12 percent from prior years. In North America, the Company is allocating a higher percentage of its capital investment to Canada primarily due to an expected increase in drilling activities, higher service costs and a stronger Canadian dollar in 2005.

Below is a discussion of the Company's production levels and expected production growth.

Production

Year Ended December 31,	**2004**	**2003**	**2002**
	(MMCFE per day)		
U.S.	1,381	1,265	1,358
Canada	994	1,062	1,013
International	442	240	200
Total production	**2,817**	**2,567**	**2,571**

The Company has a goal to achieve between three and eight percent average annual production growth. In 2004, production volumes were 2,817 MMCFE per day, representing a 10 percent increase over 2003. In 2005, the Company expects production volumes to average between 2,800 and 3,001 MMCFE per day. Production growth is expected to be driven by steady production growth in the U.S. and increased production from international operations.

In 2005, the Company expects production growth in the U.S. as a result of increased production from Cedar Creek, Bossier, south Louisiana and Bakken drilling programs. Internationally, the Company expects increased production at the sour gas fields in the East Irish Sea resulting from the expected resumption of production from the Rivers Fields. Production from the Rivers Fields commenced in October 2004; however, in November 2004, problems were encountered related to the acid plant. Repairs to the plant are progressing and production is expected to resume by the second quarter of 2005. The Company expects production in Canada to decline one to seven percent from production levels in 2004.

While these activities are subject to the risks and delays inherent to this business as discussed above, the Company believes that these sources of production growth are currently available and is now focused on identifying sources of production growth for the future.

Financial Returns

In addition to the Company's production growth goal, it is committed to generating sector-leading returns on capital employed when compared to other independent oil and gas exploration and production companies. While commodity prices play a significant role in the Company's financial returns, the Company focuses on controllable elements such as certain operating costs. In 2005, the Company expects to keep its operating and administrative costs about the same as 2004 on a per unit-of-production basis. However, it expects DD&A expense to increase about 14 to 23 percent in 2005 compared to 2004, primarily as a result of higher rates related to Canadian and International properties and unfavorable exchange rate impacts. Other costs could also increase as a result of unfavorable exchange rate impacts. Although subject to the upward cost pressures generally experienced by the industry, the Company believes it can differentiate its performance from that of its peers as a result of several initiatives underway to maintain its diligence on costs, specifically in the areas of purchasing, continuous process improvement, and knowledge transfer. The Company will continue to focus on capital efficiency and cost control.

Below are estimated and actual costs and expenses for 2005 and 2004, respectively.

	2005	2004
	(Per Mcfe)	
Transportation expense	$0.46 to $0.49	$0.44
Operating costs	0.58 to 0.62	0.57
DD&A	1.25 to 1.35	1.10
Administrative	$0.16 to $0.19	$0.21
	(In Millions)	
Exploration costs	$ 300 to $ 325	$ 258
Interest expense	$ 270 to $ 290	$ 282

Transportation expense is expected to be higher in 2005 as a result of resuming production at Rivers Fields in the International operation. This operation is expected to add approximately nine percent to the amount expended for transportation in 2004. Transportation expense for the Company's remaining operations is expected to increase slightly over 2004. Exploration costs are primarily dependent upon the size of the Company's drilling program and the success it has in finding commercial hydrocarbons. The Company cannot forecast its expected exploration success rate but it expects exploration costs to exceed the costs incurred in 2004 primarily due to higher anticipated exploration capital spending.

Income Tax Expense

The ratio of current income tax expense to total income tax expense is expected to increase from historical ratios in the Canadian, International and U.S. jurisdictions as a result of the reversal of book tax differences, initiation of production in foreign locations and the exhaustion of Alternative Minimum Tax credit carryforwards.

Commodity Prices

Commodity prices are impacted by many factors that are outside of the Company's control. Historically, commodity prices have been volatile and the Company expects them to remain that way in the future. Commodity prices are affected by numerous factors, including but not limited to, supply, market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, the Company cannot accurately predict future natural gas, NGLs and crude oil prices, and therefore, it cannot determine what impact increases or decreases in production volumes will have on future revenues or net operating cash flows. However, based on average daily natural gas production in 2004, the Company estimates that a $0.10 per MCF change in natural gas prices would impact annual natural gas revenues approximately $70 million. Also, based on average daily crude oil production in 2004, the Company estimates that a $1.00 per barrel change in crude oil prices would impact annual crude oil revenues approximately $31 million.

Potential Acquisitions

While it is difficult to predict future plans with respect to acquisitions, the Company actively seeks acquisition opportunities that build upon the Company's existing core asset basins and conform to its Basin Excellence℠ concept. Although the Company does not plan major acquisitions, they play a large role in this industry's consolidation and must be considered. Generally, acquisitions for the Company fall into one of two categories: bolt-on transactions and other acquisitions. Bolt-on transactions are usually relatively small and involve acquiring properties and assets in areas where the Company already controls a core position. Other acquisitions tend to be transactions that involve the Company acquiring a core position in an area where it either has no position or a relatively small position. In either case, the purpose of acquiring assets is to assist the Company in adding to its existing inventory of future growth opportunities. Depending on the commodity price environment at any given time, the property acquisition market can be extremely competitive. Because of its focus on sector-leading financial returns, the Company takes a disciplined approach to property acquisitions, making it difficult to predict the number and frequency of future transactions.

Financial Condition and Liquidity

The Company's total debt to total capital (total capital is defined as total debt and stockholders' equity) ratio at December 31, 2004 and December 31, 2003 was 36 percent and 41 percent, respectively. The 12 percent improvement in this ratio was attributable to the Company's strong net income and the strength of the Canadian currency partially offset by the repurchase of Common Stock. Based on the current price environment, the Company believes that it will generate sufficient cash from operating activities to fund its 2005 capital expenditures, excluding any potential major acquisition(s). At December 31, 2004, the Company had $2,179 million of cash and cash equivalents on hand, of which $1,200 million was located in Canada, $696 million in the U.S. and $283 million in

International. The Company plans to repatriate $500 million of eligible foreign earnings to the U.S. in 2005 under the one-time provisions of the American Jobs Creation Act of 2004.

Burlington Resources Capital Trust I, Burlington Resources Capital Trust II (collectively, "the Trusts"), BR and Burlington Resources Finance Company ("BRFC") have a shelf registration statement of $1,500 million on file with the Securities and Exchange Commission ("SEC"). Pursuant to the registration statement, BR may issue debt securities, shares of common stock or preferred stock. In addition, BRFC may issue debt securities and the Trusts may issue trust preferred securities. Net proceeds, terms and pricing of offerings of securities issued under the shelf registration statement will be determined at the time of the offerings. BRFC and the Trusts are wholly owned finance subsidiaries of BR and have no independent assets or operations other than transferring funds to BR's subsidiaries. Any debt issued by BRFC is fully and unconditionally guaranteed by BR. Any trust preferred securities issued by the Trusts are also fully and unconditionally guaranteed by BR. In 2001, the Company's Board of Directors authorized the Company to redeem, exchange or repurchase up to an aggregate of $990 million principal amount of debt securities.

The Company has a $1.5 billion revolving credit facility ("Credit Facility") that includes (i) a US$500 million Canadian subfacility and (ii) a US$750 million sublimit for the issuance of letters of credit, including up to US$250 million in letters of credit under the Canadian subfacility. The Credit Facility expires in July 2009 unless extended. Under the covenants of the Credit Facility, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements). The Credit Facility is available to cover debt due within one year, therefore commercial paper, credit facility notes and fixed-rate debt due within one year are generally classified as long-term debt. At December 31, 2004, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

The Company's access to funds from its Credit Facility is not restricted under any "material adverse condition" clauses. These clauses typically remove the obligation of the lenders to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations or properties considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material items of the credit agreement. While the Company's Credit Facility includes a covenant that requires the Company to report litigation or a proceeding that the Company has determined is likely to have a material adverse effect on the consolidated financial condition of the Company, the obligation of the lenders to fund the Credit Facility is not conditioned on the absence of such litigation or proceeding.

Net cash provided by operating activities in 2004 increased $897 million and $1,887 million over 2003 and 2002, respectively, primarily due to higher commodity prices and higher production volumes partially offset by higher costs and expenses, excluding non-cash expenses. Key drivers of net operating cash flows are commodity prices, production volumes and costs and expenses. Average natural gas prices increased 14 percent and 72 percent over 2003 and 2002, respectively. Crude oil prices increased 33 percent and 50 percent over 2003 and 2002, respectively, while NGLs prices increased 24 percent and 76 percent over the same period. Production volumes increased 10 percent over both 2003 and 2002. Although the Company believes that 2005 production volumes will exceed 2004 levels, it is unable to predict future commodity prices, and as a result cannot provide any assurance about future levels of net cash provided by operating activities. Net cash provided by operating activities in 2004 is not necessarily indicative of future cash flows from operating activities. See page 19 for a discussion of commodity prices.

The increase in net cash provided by operating activities resulting from higher commodity prices and higher production volumes were partially offset by higher costs and expenses. In 2004, costs and expenses that affect net operating cash provided by operating activities primarily include operating costs, taxes other than income taxes, transportation expense, and administrative expenses. These costs and expenses increased $281 million and $410 million over 2003 and 2002, respectively. Operating costs and taxes other than income taxes represented the largest increase in these costs. Operating costs include well operating expenses, which are expenses incurred to operate the Company's wells and equipment on producing leases. The increase related to well operating expenses accounted for 36 percent and 25 percent of the increase in costs and expenses over 2003 and 2002, respectively. Taxes other than income taxes include severance taxes, which are directly correlated to crude oil and natural gas revenues. The increase related to severance taxes accounted for 22 percent and 29 percent of the increase in costs and expenses over 2003 and 2002, respectively. For revenue, price, volume and costs and expense variances, see tables and explanations on pages 27-29.

Generally, producing natural gas and crude oil reservoirs have declining production rates. Production rates are impacted by numerous factors, including but not limited to, geological, geophysical and engineering matters, production curtailments and restrictions, weather, market demands and the Company's ability to replace depleting reserves. The Company's inability to adequately replace reserves could result in a decline in production volumes, one of the key drivers of generating net operating cash flows. The Company's reserve replacement ratio for the year ended December 31, 2004 was 125 percent and has averaged 142 percent over the last three years. Results for any year are a function of the success of the Company's drilling program and acquisitions. While program results are difficult to predict, the Company's current drilling inventory provides the Company opportunities to replace its production in 2005.

The Company has various contractual obligations primarily related to leases for office space, other property and equipment and demand charges on firm transportation agreements for its production of natural gas and crude oil. The Company expects to fund these contractual obligations with cash generated from operations. The following table summarizes the Company's contractual obligations at December 31, 2004.

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(In Millions)		
Total debt(1)	$3,930	$ 2	$ 978	$150	$2,800
Interest payments on long-term debt	3,754	272	721	424	2,337
Transportation demand charges(2)	946	165	325	134	322
Non-cancellable operating leases(2)	288	30	84	58	116
Postretirement benefits(3)	29	3	9	6	11
Pension funding(3)	12	12	—	—	—
Drilling rig commitments(2)	11	7	4	—	—
Total Contractual Obligations	**$8,970**	**$491**	**$2,121**	**$772**	**$5,586**

(1) See Note 9 of Notes to Consolidated Financial Statements for details of long-term debt.

(2) See Note 14 of Notes to Consolidated Financial Statements for discussion of these commitments.

(3) See Note 13 of Notes to Consolidated Financial Statements for discussion of the Company's benefit plans. The Company expects to contribute $12 million to its U.S. pension plans in 2005.

The Company also has liabilities of $468 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2004. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. See Note 10 of Notes to Consolidated Financial Statements.

Certain of the Company's contracts require the posting of collateral upon request in the event that the Company's long-term debt is rated below investment grade or ceases to be rated. Those contracts primarily consist of hedging agreements and two long-term natural gas transportation agreements. A few of the hedging agreements also require posting of collateral if the market value of the transactions thereunder exceed a specified dollar threshold that varies with the Company's credit rating. As of December 31, 2004, the Company has a BBB+ long-term debt rating from Standard & Poors and Baa1 Moody's Investors Service ("Moody's") rating. Investment grade is designated as all ratings above BB+ for Standard & Poors and Ba1 for Moody's.

While the mark-to-market positions under the hedging agreements will fluctuate with commodity prices, as a producer, the Company's liquidity exposure due to its outstanding derivative instruments tends to increase when commodity prices increase. Consequently, the Company is most likely to have its largest unfavorable mark-to-market position in a high commodity price environment when it is least likely that a credit support requirement due to an adverse rating action would occur. At December 31, 2004, the aggregate unfavorable mark-to-market position under the aforementioned hedging agreements was approximately $11 million. In the case of the Canadian transportation agreements, the collateral required would be an amount equal to 12 months of estimated demand charges. That amount totaled approximately $34 million as of December 31, 2004.

In the normal course of business, the Company has performance obligations which are supported by surety bonds or letters of credit. These obligations are primarily for site restoration and dismantlement, royalty payment appeals and excise tax exemption certifications where governmental organizations require such support.

Changes in credit rating also impact the cost of borrowing under the Company's Credit Facility, but have no impact on availability of credit under the agreements.

In December 2000, the Company's Board of Directors ("Board") authorized the repurchase of up to $1 billion of the Company's Common Stock. Through April 30, 2003, the Company had repurchased $816 million of its Common Stock under the program authorized in December 2000. In April 2003, the Company's Board voted to restore the authorization level to $1 billion effective May 1, 2003. Through December 7, 2004, the Company had repurchased $712 million of its Common Stock under the program authorized in April 2003. In December 2004, the Company's Board again voted to restore the authorization level to $1 billion.

During 2004, the Company repurchased approximately 14 million shares of its Common Stock for approximately $522 million and, as of December 31, 2004, had authority to repurchase an additional $952 million of its Common Stock under the current authorization. As of December 31, 2004, $8 million of the share repurchases were not cash settled; however, $4 million related to 2003 repurchases were settled during the current year. Since December 2000, the

Company has repurchased approximately 61.8 million shares of its Common Stock for $1.6 billion. Share amounts have been adjusted to reflect the 2-for-1 stock split ("split") of the Company's Common Stock effective June 1, 2004.

The Company has certain other commitments and uncertainties related to its normal operations. Management believes that there are no other commitments or uncertainties that will have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

Off-Balance Sheet Arrangements

The Company has off-balance sheet arrangements that it believes have not and are not reasonably likely to have a material current or future effect on the Company's results of operations, financial condition, liquidity, capital expenditures or capital resources. These off-balance sheet arrangements consist of equity investments in two entities that the Company accounts for under the equity method. The book values of the Company's interests in Lost Creek Gathering Company, L.L.C. ("Lost Creek") and Evangeline Gas Pipeline Company ("Evangeline") are $19 million and $2 million, respectively. As of December 31, 2004, Lost Creek had outstanding debt totaling $42 million and Evangeline had outstanding debt totaling $33 million. Lost Creek and Evangeline's debts are non-recourse to the Company, and as a result, the Company has no legal responsibility or obligation for these debts. Management believes that Lost Creek and Evangeline are financially stable and therefore will be in a position to repay their outstanding debts.

Capital Expenditures and Resources

Capital expenditures were as follow.

Year Ended December 31,	2004	2003	2002	2004 vs. 2003 Increase (Decrease)	2004 vs. 2003 (%) Increase (Decrease)	2004 vs. 2002 Increase (Decrease)	2004 vs. 2002 (%) Increase (Decrease)
				($ In Millions)			
Oil and gas							
Development	$1,273	$1,056	$ 779	$ 217	21%	$ 494	63%
Exploration	286	301	218	(15)	(5)	68	31
Acquisitions	85	228	604	(143)	(63)	(519)	(86)
Total oil and gas	**1,644**	**1,585**	**1,601**	**59**	**4**	**43**	**3**
Plants and pipelines	66	163	193	(97)	(60)	(127)	(66)
Administrative and other	37	40	43	(3)	(8)	(6)	(14)
Total capital expenditures	**$1,747**	**$1,788**	**$1,837**	**$ (41)**	**(2)%**	**$ (90)**	**(5)%**

The Company's consolidated capital expenditures were down 2 percent and 5 percent compared to 2003 and 2002, respectively. Excluding acquisitions, the Company's capital spending related to internal development and exploration was up 15 and 56 percent compared to 2003 and 2002, respectively. Capital expenditures in 2005, excluding proved property acquisitions, are expected to be approximately $2 billion, up 21 percent over 2004, primarily due to anticipated higher project counts in major operating areas, increased service costs, and higher foreign currency exchange rates, particularly in Canada. The Company believes that 2005 estimated spending is sufficient to add adequate reserves and achieve the target of three to eight percent average annual production growth. Capital expenditures in 2005 are expected to be primarily for internal development and exploration of oil and gas properties. Capital spending in 2005 related to internal development and exploration is expected to be about 22 percent higher than 2004 and is expected to be funded from internally generated cash flows.

During 2002, the Company sold a processing facility and other non-core, non-strategic properties that consisted of high cost structure, high production volume decline rates and limited growth opportunities. As a result of these property sales, the Company generated proceeds, before post closing adjustments, of approximately $1.2 billion and recognized a net pretax gain of $68 million. The producing properties that were sold contributed approximately 230 MMCFE per day during 2002. The Company used a portion of the proceeds generated from property sales to retire debt and for general corporate purposes.

Marketing

North America (U.S. and Canada)

The Company's marketing strategy is to maximize the value of its production by developing marketing flexibility from the wellhead to its ultimate sale. The Company's natural gas production is gathered, processed, exchanged and transported utilizing various firm and interruptible contracts and routes to access higher value market hubs. The Company's customers include local distribution companies, electric utilities, industrial users and marketers. The Company maintains the capacity to ensure its production can be marketed either at the wellhead or downstream at market sensitive prices.

All of the Company's crude oil production is sold to third parties at the wellhead or transported to market hubs where it is sold or exchanged. NGLs are typically sold at field plants or transported to market hubs and sold to third parties. Downgrades or the inability of the Company's customers to maintain their credit rating or credit worthiness could result in an increase in the allowance for unrecoverable receivables from natural gas, NGLs or crude oil revenues or it could result in a change in the Company's assumption process of evaluating collectibility based on situations regarding specific customers and applicable economic conditions.

International

The Company's International production is marketed to third parties either directly by the Company or by the operators of the properties. Production is sold at the platforms or various sales points based on spot or contract prices.

Qualitative and Quantitative Disclosure About Market Risk

Commodity Risk

Substantially all of the Company's natural gas, NGLs and crude oil production is sold on the spot market or under short-term contracts at market sensitive prices. Spot market prices for domestic natural gas and crude oil are subject to volatile trading patterns in the commodity futures market, including among others, the New York Mercantile Exchange ("NYMEX"). Quality differentials, worldwide political developments and the actions of the Organization of Petroleum Exporting Countries also affect crude oil prices.

There is also a difference between the NYMEX futures contract price for a particular month and the actual cash price received for that month in a North America producing basin or at a North America market hub, which is referred to as "basis differentials." Basis differentials can vary widely depending on various factors, including but not limited to, local supply and demand.

The Company utilizes over-the-counter price and basis swaps as well as options to hedge its production in order to decrease its price risk exposure. The gains and losses realized as a result of these price and basis derivative transactions are substantially offset when the hedged commodity is delivered. In order to accommodate the needs of its customers, the Company also uses price swaps to convert natural gas sold under fixed-price contracts to market sensitive prices.

The Company recognizes all derivatives as either assets or liabilities on the balance sheet and measures those instruments at fair value. The requisite accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

The Company uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of natural gas and crude oil may have on the fair value of the Company's derivative instruments. For example, at December 31, 2004, the potential decrease in fair value of derivative instruments assuming a 10 percent adverse movement (an increase in the underlying commodities prices) would result in a $50 million decrease in the net unrealized gain. The derivative instruments in place at December 31, 2004 hedged approximately 15 percent of the Company's expected natural gas production volumes through 2005.

For purposes of calculating the hypothetical change in fair value, the relevant variables include the type of commodity, the commodity futures prices, the volatility of commodity prices and the basis and quality differentials. The hypothetical change in fair value is calculated by multiplying the difference between the hypothetical price (adjusted for any basis or quality differentials) and the contractual price by the contractual volumes. As more fully described in Note 1 of Notes to Consolidated Financial Statements, the Company periodically assesses the effectiveness of its derivative instruments in achieving offsetting cash flows attributable to the risks being hedged. Changes in basis differentials or notional amounts of the hedged transactions could cause the derivative instruments to fail the effectiveness test and result in mark-to-market accounting for the affected derivative transactions which would be reflected in the Company's current period earnings.

Credit and Market Risks

The Company manages and controls market and counterparty credit risk through a system of established internal controls and procedures which are reviewed on a periodic basis. The Company attempts to minimize credit risk exposure to counterparties through formal credit policies and monitoring procedures as well as the use of netting arrangements and requiring letters of credit or parent guarantees, when necessary. Accounts receivable are stated at historical value which approximates fair market value on the Company's Consolidated Balance Sheet and no single customer of the Company constitutes more than 11 percent of the Company's accounts receivable balance at December 31, 2004. In the normal course of business, collateral is not required for financial instruments with credit risk. The fair value of the Company's fixed-rate debt is subject to change based on changes in interest rates. From time to time, the Company enters into financial derivatives to manage this exposure. Based on financial derivative transactions in place as of year-end 2004, a 10 percent adverse move in interest rates (an increase in the underlying interest rates) would result in less than a $1 million increase in interest expense. Additionally, the Company has cash investments that it manages based on internal investment guidelines that emphasize liquidity and preservation of capital, and such cash investments are stated at historical cost which approximates fair market value on the Company's Consolidated Balance Sheet.

Foreign Currency Risk

The Company has exposure to currency risk in certain of its foreign subsidiaries where the functional currency is the U.S. dollar and where some of the transactions are denominated in the local currency. The Company monitors and manages its exposure to foreign currency risk in these subsidiaries primarily by balancing local currency monetary assets and liabilities. The Company does not actively manage foreign currency risk in its other foreign subsidiaries where the U.S. dollar is not the functional currency, primarily Canada, since the majority of transactions are denominated in the local currency. A substantial amount of the Company's cash is located in Canada, in Canadian dollars, which provides a natural hedge against foreign currency risk. As of December 31, 2004, the Company had no foreign currency financial derivatives.

Dividends

On January 26, 2005, the Board declared a Common Stock quarterly cash dividend of $0.085 per share, payable April 8, 2005 to shareholders of record on March 9, 2005. During the third quarter of 2004, the Company increased its quarterly cash dividend from $0.075 to $0.085 per share, representing a 13 percent increase. Dividend levels are determined by the Board based on profitability, capital expenditures, financing and other factors. The Company declared and paid cash dividends on Common Stock totaling approximately $125 million and $122 million, respectively, during 2004.

On January 21, 2004, the Company's Board approved a 2-for-1 split of the Company's Common Stock in the form of a share distribution, subject to shareholder approval of an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares from 325 million to 650 million. On April 21, 2004, the Company's shareholders approved the amendment. As a result, the split was paid in the form of a share distribution on June 1, 2004 to shareholders of record on May 5, 2004.

Application of Critical Accounting Policies

Oil and Gas Reserves

The Company's estimate of proved reserves reflects quantities of natural gas, NGLs and crude oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic conditions. The process of estimating quantities of natural gas, NGLs and crude oil reserves requires judgment in the evaluation of all available geological, geophysical, engineering and economic data, including production data, reservoir pressure data and data collected as a result of development or exploration drilling. Economic and operating conditions, such as product prices, the availability of additional development capital, operating costs, development costs, production tax rates, the installation of additional infrastructure, regulatory approval and actions of domestic or foreign governments influence the estimation of reserves. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Company's reserves.

The Company has policies and procedures through which the required engineering, geological, and economic data is gathered and proved reserves are estimated. Experienced and qualified Company engineers prepare the reserve estimates. These estimates are subjected to a series of internal reviews to ensure that they are technically and legally justified and therefore reasonable, prepared using generally accepted principles and practices, and comply with SEC Regulations. A corporate staff of engineers conducts oversight and audit of the reserve estimates. Furthermore, the reserve maintenance process requires review and approval of every change to the proved reserve ledger, the most significant requiring approval by the Company's Chief Engineer.

The Company also engages independent oil and gas engineering consulting firms to review its proved reserves base. The firms determine both the specific properties reviewed and the aggregate magnitude they require for review. Typically, at least 80 percent of the estimated proved reserves receive external review. The Company's reserve estimates during 2002, 2003, and 2004 were subjected to this external review by the independent oil and gas consultants, who in their judgment determined the estimates to be reasonable in the aggregate. At the conclusion of their external review, the audit firms issue a written opinion and present their findings to the members of the Board of Directors' Audit Committee. For more information, see the independent oil and gas consultant's letters on pages 69-73.

Despite the inherent imprecision in these engineering estimates, the Company's reserves are used throughout its financial statements. As described in Note 1 of Notes to Consolidated Financial Statements, the Company uses the unit-of-production method to amortize its oil and gas properties. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision or, in some cases, an impairment charge in the period of the revision. Although revisions to reserve estimates in previous years have averaged less than one percent, a five percent negative or adverse revision to the Company's consolidated proved reserves would result in an increase in annual DD&A expense of approximately $66 million. See the Supplementary Financial Information for reserve data.

Successful Efforts Method of Accounting

The Company accounts for its oil and gas properties using the successful efforts method of accounting. Acquisition and development costs are capitalized and amortized using the unit-of-production method based on total proved and proved developed reserves, respectively, estimated by the Company's reserve engineers. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision. Unsuccessful exploration or dry hole wells are expensed in the period in which the wells are determined to be dry and could have a significant effect on results of operations.

Carrying Value of Long-lived Assets

As more fully described in Note 1 of Notes to Consolidated Financial Statements, the Company performs an impairment analysis on its proved properties whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable and annually for the Company's unproved reserves. Cash flows used in the impairment analysis are determined based upon management's estimates of proved natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves. Downward revisions in estimated reserve quantities, increases in future cost estimates or depressed natural gas, NGLs and crude oil prices could cause the Company to reduce the carrying amounts of its properties. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Because natural gas, NGLs and crude oil prices are volatile, these estimates are inherently imprecise. A five percent negative or adverse revision to the Company's proved reserves combined with a 10 percent decline in the natural gas price used to identify fields that are potentially impaired would have resulted in a pretax impairment charge of approximately $105 million ($70 million after tax) for the year ended December 31, 2004. See Note 16 of Notes to Consolidated Financial Statements for impairment of oil and gas properties.

The Company's lease acquisition costs are not subject to the impairment analysis described above, however, a portion of the costs associated with such properties is subject to amortization on a composite basis based on past experience and average property lives. On an annual basis, the Company monitors the estimated success rate used to determine the amount of lease acquisition costs that are not subject to amortization and makes an adjustment, if needed. Typically, these adjustments do not have a significant impact on future amortization. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity are expensed in the period the determination is made. The rate at which the unproved properties are written off depends on the timing and success of the Company's future exploration program.

Asset Retirement Obligations ("ARO")

The Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment as well as to dismantle and abandon plants at the end of oil and gas production operations. The Company records the fair value of a liability for ARO in the period in which it is incurred and a corresponding increase in the carrying amount of the related asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using a systematic and rational method. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as additional depreciation, depletion and amortization expense in the Consolidated Statement of Income.

Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. The Company uses the present value of estimated cash flows related to its ARO to determine the fair value. The present value calculation includes numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. Abandonment cost estimates are determined by the Company's reserve engineers based on actual costs incurred to abandon similar wells, and their knowledge of the respective wells. The Company has been unable to determine the accuracy of these estimates due to the limited amount of abandonment activity since the adoption of SFAS No. 143. The Company uses an inflation factor determined by analyzing an industry specific price index that it updates annually. Timing of settlement is based on reserve estimates and is subject to the same inherent imprecision described above for oil and gas reserves. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the related asset. A five percent increase in the Company consolidated ARO would result in a $23 million increase in the Company's obligation and a $1.5 million increase in annual accretion expense.

Goodwill

As required, the Company performs an annual impairment assessment in lieu of periodic amortization of goodwill. The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. The Company determined the fair value of its Canadian reporting unit using a combination of the income approach and the market approach. Under the income approach, the Company estimated the fair value of the reporting unit based on the present value of expected future cash flows. Under the market approach, the Company estimated the fair value based on market multiples of reserves and production for comparable companies.

The income approach is dependent on a number of factors including estimates of forecasted revenue and costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar or depressed natural gas, NGLs and crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. In the market approach, the Company makes certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although the Company based its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. In 2004, the Company used a professional valuation services firm to assist in preparing its annual valuation of goodwill. At December 31, 2004, the fair value of the Canadian reporting unit exceeded its carrying amount and the use of other reasonable assumptions would not have changed the outcome of the impairment test.

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company's net interest. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales prices for natural gas, NGLs and crude oil are adjusted for transportation costs and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third-party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer.

Legal, Environmental and Other Contingencies

A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies in dealing with similar matters, and the decision of management on how it intends to respond to a particular contingency (for example, a decision to contest a matter vigorously or a decision to seek a negotiated settlement). The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company.

Results of Operations

Year Ended December 31, 2004 Compared With Year Ended December 31, 2003

The Company's consolidated net income increased $326 million or $0.86 diluted earnings per common share ("per share") in 2004 primarily due to higher commodity prices and higher production volumes. Net income in 2004 and 2003 included charges, net of taxes, of $59 million or $0.15 per share and $38 million or $0.09 per share, respectively, related to the impairment of oil and gas properties primarily in Canada. Net income in 2004 and 2003 included income tax benefits of $23 million or $0.06 per share and $203 million or $0.51 per share, respectively, related to the reduction of the Canadian federal income tax rate. Net income in 2004 and 2003 also included income tax benefits of $45 million or $0.11 per share and $11 million or $0.02 per share, respectively, related to the reduction of the Alberta provincial corporate income tax rate. In 2004, the Company recorded a U.S. income tax expense of $26 million or $0.07 per share related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004. Net income in 2003 also included a net-of-tax cumulative effect of change in accounting principle charge of $59 million or $0.15 per share related to the adoption of SFAS No. 143, *Asset Retirement Obligations.* See Note 10 of Notes to Consolidated Financial Statements for more information. Per share amounts for 2003 have been retroactively adjusted to reflect the 2-for-1 split of the Company's Common Stock effective June 1, 2004.

Below is a discussion of prices, volumes and revenue variances.

Price and Volume Variances

			2004 vs. 2003		
Year Ended December 31,	**2004**	**2003**	**Increase**	**(%) Increase**	**Increase**
					(In Millions)
Price Variance					
Natural gas sales prices (per MCF)	$ 5.49	$ 4.83	$0.66	14%	$462
NGLs sales prices (per Bbl)	25.38	20.40	4.98	24	119
Crude oil sales prices (per Bbl)	$36.25	$27.22	$9.03	33%	282
Total price variance					**$863**
Volume Variance					
Natural gas sales volumes (MMCF per day)	1,914	1,899	15	1%	$ 35
NGLs sales volumes (MBbls per day)	65.3	64.8	0.5	1	5
Crude oil sales volumes (MBbls per day)	85.2	46.5	38.7	83%	387
Total volume variance					**$427**

Revenue Variances

			2004 vs. 2003	
Year Ended December 31,	**2004**	**2003**	**Increase (Decrease)**	**% Increase (Decrease)**
			($ In Millions)	
Natural gas	$3,847	$3,331	$ 516	15%
NGLs	606	482	124	26
Crude oil	1,131	462	669	145
Processing and other	34	36	(2)	(6)
Total revenues	**$5,618**	**$4,311**	**$1,307**	**30%**

Revenues

The Company's consolidated revenues increased $1,307 million in 2004. Higher revenues were primarily due to higher commodity prices and higher production volumes, resulting in increased revenues of $863 million and $427 million, respectively. Revenue variances related to commodity prices and sales volumes are described below.

Price Variances

Commodity prices are one of the key drivers of earnings generation and net operating cash flow for the Company. Higher commodity prices contributed $863 million to the increase in revenues in 2004. Average natural gas prices, including a $0.01 realized loss per MCF related to hedging activities, increased $0.66 per MCF during 2004, resulting in increased revenues of $462 million. Average crude oil prices, including a $0.99 realized loss per barrel related to hedging activities, increased $9.03 per barrel in 2004, resulting in increased revenues of $282 million. Average NGLs prices increased $4.98 per barrel in 2004, resulting in higher revenues of $119 million. As discussed on page 19, commodity prices are affected by many factors that are outside of the Company's control. Therefore, commodity prices received by the Company during 2004 are not necessarily indicative of prices it may receive in the future. Depressed commodity prices over a significant period of time would result in reduced cash from operating activities potentially causing the Company to expend less on its capital program. Lower spending on the capital program could result in a reduction of the amount of production volumes the Company is able to produce. The Company cannot accurately predict future commodity prices, and cannot be certain whether these events will occur.

Volume Variances

Sales volumes are another key driver that impact the Company's earnings and net operating cash flow. Higher sales volumes in 2004 resulted in increased revenues of $427 million. Average crude oil sales volumes increased 38.7 MBbls per day in 2004, resulting in increased revenues of $387 million. The increase in crude oil sales volumes was primarily due to higher production from International's new project start-ups in late 2003 from fields in offshore China, Algeria and Ecuador, which contributed increased production of 17.9 MBbls per day, 8.6 MBbls per day and 3.9 MBbls per day, respectively, in 2004. Production from the U.S. Cedar Creek Anticline increased 6.6 MBbls per day and the Bakken Shale increased 1.5 MBbls per day in 2004.

Average natural gas sales volumes increased 15 MMCF per day in 2004, resulting in increased revenues of $35 million. Average natural gas sales volumes increased primarily due to higher production from the Madden Field, CLAM in the Dutch sector of the North Sea, and south Louisiana, which contributed increased production of 31 MMCF per day, 29 MMCF per day and 6 MMCF per day, respectively, in 2004. These increases were partially offset by lower production volumes in Canada of 48 MMCF per day. Production volumes in Canada were down primarily due to higher service costs and the Canadian dollar strengthening against the U.S. dollar that led to fewer net wells drilled in 2004 versus 2003, unfavorable weather conditions that impacted program execution during 2004 and lower than expected new well productivity in certain areas. Average NGLs sales volumes increased 0.5 MBbls per day in 2004, resulting in higher revenues of $5 million over 2003.

The Company has a goal to achieve between three and eight percent average annual production growth; therefore, future production volumes are expected to increase over the current period. See discussion under "Outlook" on page 18 for guidance on production volumes. *As mentioned above, depressed prices over an extended period of time or other unforeseen events could occur that would result in the Company being unable to sustain a capital program that allows it to meet its production growth goals. However, the Company cannot predict whether such events will occur.*

Below is a discussion of total costs and other income—net.

Total Costs and Other Income—Net

			2004 vs. 2003	
Year Ended December 31,	**2004**	**2003**	**Increase (Decrease)**	**% Increase (Decrease)**
			($ In Millions)	
Costs and other income — net				
Taxes other than income taxes	$ 260	$ 187	$ 73	39%
Transportation expense	453	408	45	11
Operating costs	587	475	112	24
Depreciation, depletion and amortization	1,137	927	210	23
Exploration costs	258	252	6	2
Impairment of oil and gas properties	90	63	27	43
Administrative	215	164	51	31
Interest expense	282	260	22	8
(Gain)/loss on disposal of assets	13	(8)	(21)	(263)
Other expense (income) — net	19	13	6	46
Total costs and other income — net	**$3,314**	**$2,741**	**$573**	**21%**

Total costs and other income—net increased $573 million in 2004. This increase in total costs and other income—net was primarily due to the items discussed below. The increase in the exchange rate in Canada during 2004 impacted certain costs and expenses for the Company. Changes in the value of the Canadian dollar versus the U.S. dollar could impact costs and expenses in future years. However, at this time, the Company cannot predict what impact the

Canadian exchange rate will have on costs and expenses in the future. See discussion under "Outlook" on page 19 for guidance on costs and expenses in 2005.

DD&A expense increased $210 million primarily due to higher production and higher unit-of-production rates on International properties and higher unit-of-production rates on Canadian properties. Operating costs increased $112 million compared to 2003. This increase is primarily due to higher well operating expenses, which include direct expenses incurred to operate the Company's wells and equipment on producing leases. Well operating expenses were higher primarily due to increased repair and maintenance expenses, higher workover activity and changes in exchange rates.

Taxes other than income taxes increased $73 million primarily due to higher production taxes resulting from higher crude oil and natural gas revenues. Taxes other than income taxes include severance taxes which are directly correlated to natural gas and crude oil revenues. Administrative expense increased $51 million primarily due to higher stock-based compensation expense, excluding stock options, related to a higher stock price for the Company and higher legal expenses. Transportation expense increased $45 million primarily due to operations related to new start-up projects in late 2003 in International operations and higher rates in Canada. Interest expense increased $22 million primarily due to no capitalized interest incurred on capital projects in 2004.

The Company performs an impairment analysis annually for unproved reserves or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon management's estimates of natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves. In 2004 and 2003, the Company recorded non-cash charges of $90 million and $63 million, respectively, related to the impairment of oil and gas properties. The impairments in 2004 and 2003 were related to undeveloped properties in Canada and performance-related downward reserve adjustments, also primarily in Canada, respectively.

Exploration costs increased $6 million due to higher geological and geophysical ("G&G") and other expenses of $20 million partially offset by lower amortization of undeveloped lease costs of $10 million and lower exploratory dry hole costs of $4 million. Exploration expense fluctuates from period to period primarily due to the amount the Company expends on its exploration capital program and its success rate; however, the success rate is difficult to predict. Of the exploratory wells drilled by the Company in 2004, 2003 and 2002, the Company experienced a success rate in the range of approximately 50 to 66 percent during that period of time. These success rates are not necessarily indicative of future rates. The Company capitalizes costs incurred to drill exploratory wells pending determination of whether the wells have found an adequate amount of economically recoverable reserves to be classified as proved. When a determination cannot be made at the time drilling is completed, the costs are deferred until a determination can be made. At December 31, 2004, $23 million of deferred exploration costs were included in oil and gas properties on the Company's Consolidated Balance Sheet. Some or all of these costs could be included in exploration expense in future periods. In 2004 and 2003, $14 million and $7 million, respectively, were reclassified from oil and gas properties to exploration expense.

Income Tax Expense

Income tax expense increased $467 million in 2004, primarily due to an increase in pretax income of $734 million. In 2004, the Company recorded $26 million of U.S. income tax expense related to its plan to repatriate $500 million of eligible foreign earnings under the one-time provisions of the American Job Creation Act of 2004. In addition, income taxes on foreign earnings in excess of the U.S. tax rate resulted in an increase in tax expense of $19 million in 2004. The reduction of the Canadian federal income tax rate resulted in an income tax benefit of $45 million in 2004 compared to a benefit of $203 million in 2003. The reduction of the Alberta provincial corporate income tax rate resulted in an income tax benefit of $23 million in 2004 compared to a benefit of $11 million in 2003. The Company also recorded a net tax benefit of $10 million in 2004 related to the settlement of the 1999-2000 audits of its Section 29 Tax Credits, and recorded a net tax benefit of $27 million in 2003 related to the settlements of the 1996-1998 audits of its Section 29 Tax Credits. As a result of the increase in exchange rates, the Company recorded higher tax benefits of $7 million related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly-owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada. Substantially all of the increase in the tax benefit of the cross-border financing deduction from 2003 to 2004 was due to the strengthening of the Canadian dollar. This benefit is not expected to fluctuate in the future for reasons other than changes in exchange rate and debt levels.

Year Ended December 31, 2003 Compared With Year Ended December 31, 2002

The Company's consolidated net income increased $747 million or $1.87 per share in 2003 primarily due to higher commodity prices. Net income in 2003 included tax benefits of $203 million or $0.51 per share and $11 million or $0.02 per share related to the reduction of the Canadian federal income tax and the Alberta provincial corporate income tax rates, respectively. Net income in 2002 included a tax benefit of $26 million or $0.06 per share related to the reduction of the Alberta provincial corporate income tax rate in Canada and the reversal of a tax valuation reserve of

$27 million or $0.07 per share related to the sale of assets in the United Kingdom ("U.K.") sector of the North Sea. Per share amounts for 2003 and 2002 have been retroactively adjusted to reflect the 2-for-1 split of the Company's Common Stock effective June 1, 2004.

Below is a discussion of prices, volumes and revenue variances.

Price and Volume Variances

				2003 vs. 2002	
Year Ended December 31,	**2003**	**2002**	**Increase (Decrease)**	**(%) Increase (Decrease)**	**Increase (Decrease)**
					(In Millions)
Price Variance					
Natural gas sales prices (per MCF)	$ 4.83	$ 3.20	$1.63	51%	$1,129
NGLs sales prices (per Bbl)	20.40	14.46	5.94	41	140
Crude oil sales prices (per Bbl)	$27.22	$24.11	$3.11	13%	53
Total price variance					**$1,322**
Volume Variance					
Natural gas sales volumes (MMCF per day)	1,899	1,916	(17)	(1)%	$ (20)
NGLs sales volumes (MBbls per day)	64.8	60.1	4.7	8	25
Crude oil sales volumes (MBbls per day)	46.5	49.1	(2.6)	(5)%	(23)
Total volume variance					**$ (18)**

Revenue Variances

			2003 vs. 2002	
Year Ended December 31,	**2003**	**2002**	**Increase**	**% Increase**
		($ in Millions)		
Natural gas	$3,331	$2,209	$1,122	51%
NGLs	482	317	165	52
Crude oil	462	432	30	7
Processing and other	36	10	26	260
Total revenues	**$4,311**	**$2,968**	**$1,343**	**45%**

Revenues

The Company's consolidated revenues increased $1,343 million in 2003. Higher revenues were primarily due to higher commodity prices, resulting in increased revenues of $1,322 million. Revenues also increased $26 million due to higher processing and other revenues. Processing and other revenues increased $20 million and $19 million, respectively, due to ineffectiveness of cash-flow and fair-value hedges and changes in fair value instruments that do not qualify for hedge accounting. The amounts were partially offset by a decrease of $18 million related to lower sales volumes and $19 million related to the sale of a processing facility in June 2002. The revenue variances related to commodity prices and sales volumes are described below.

Price Variances

Commodity prices are one of the key drivers of earnings and net operating cash flow generation. Higher commodity prices contributed $1,322 million to the increase in revenues in 2003. Average natural gas prices, including a $0.09 realized loss per MCF related to hedging activities, increased $1.63 per MCF in 2003 resulting in increased revenues of $1,129 million. Average NGLs prices increased $5.94 per barrel in 2003, resulting in higher revenues of $140 million. Average crude oil prices, including a $0.09 realized loss per barrel related to hedging activities, increased $3.11 per barrel in 2003, resulting in increased revenues of $53 million. See page 19 for a discussion of commodity prices.

Volume Variances

Sales volumes are another key driver that impact the Company's earnings and net operating cash flow generation. Lower sales volumes in 2003 resulted in a decline in revenues of $18 million. Average crude oil sales volumes decreased 2.6 MBbls per day in 2003, reducing revenues $23 million. Average crude oil sales volumes decreased 13.8 MBbls per day primarily due to asset sales in 2002 in the Gulf of Mexico, Canada, the U.K. sector of the North Sea and the Williston Basin. This decrease in crude oil sales volumes was partially offset by an increase of 10.8 MBbls per day resulting from higher production at Ourhoud Field and the Company-operated MLN Field in Algeria, south Louisiana and Cedar Creek. Average natural gas sales volumes decreased 17 MMCF per day in 2003, resulting in decreased revenues of $20 million. Average natural gas sales volumes decreased 108 MMCF per day primarily due to asset sales in 2002 in the Gulf of Mexico, the U.K. sector of the North Sea and Sonora. This decrease in natural gas sales volumes was partially offset by an increase of 93 MMCF per day primarily as a result of the drilling programs in Canada and the Fort Worth Basin. Average NGLs sales volumes increased 4.7 MBbls per day in 2003, resulting in higher revenues of $25 million year over year. Average NGLs sales volumes increased 4.8 MBbls per day in the San Juan Basin and the Fort Worth Basin.

Below is a discussion of total costs and other income—net.

Total Costs and Other Income—Net

			2003 vs. 2002	
Year Ended December 31,	**2003**	**2002**	**Increase (Decrease)**	**% Increase (Decrease)**
			($ In Millions)	
Costs and other income—net				
Taxes other than income taxes	$ 187	$ 123	$ 64	52%
Transportation expense	408	354	54	15
Operating costs	475	467	8	2
Depreciation, depletion and amortization	927	833	94	11
Exploration costs	252	286	(34)	(12)
Impairment of oil and gas properties	63	—	63	—
Administrative	164	161	3	2
Interest expense	260	274	(14)	(5)
Gain on disposal of assets	(8)	(68)	(60)	(88)
Other expense (income)—net	13	(31)	(44)	(142)
Total costs and other income—net	**$2,741**	**$2,399**	**$342**	**14%**

Total costs and other income—net increased $342 million in 2003. This increase in total costs and other income—net was primarily due to items discussed below. The increase in the exchange rate in Canada during 2003 impacted certain costs and expenses for the Company. Changes in the value of the Canadian dollar versus the U.S. dollar could impact costs and expenses in future years. However, at this time, the Company cannot predict what impact the Canadian exchange rate will have on costs and expenses in the future.

DD&A expense increased $94 million primarily due to higher unit-of-production rates on the Canadian properties which have higher rates than average unit-of-production rates for the Company partially offset by the divestiture of higher cost properties in 2002 and lower crude oil and natural gas production volumes. Taxes other than income taxes increased $64 million primarily due to higher production taxes resulting from higher crude oil and natural gas revenues.

The Company performs an impairment analysis annually for unproved reserves or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon management's estimates of natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves. In 2003, the Company recorded charges of $63 million related to the impairment of oil and gas properties due to performance-related downward reserve adjustments associated with certain properties primarily in Canada.

Gain on disposal of assets decreased $60 million primarily due to the divestiture program that was announced by the Company in late 2001 and completed in late 2002. Transportation expense increased $54 million primarily due to higher contract rates primarily resulting from the sale of a processing facility in 2002. Other expense (income)—net increased $44 million primarily due to lower interest income and higher expenses related to foreign currency transactions.

Exploration costs decreased $34 million primarily due to lower drilling rig expenses of $32 million attributable to a loss incurred by the Company in 2002 related to the remaining terms of a sublease of a deepwater drilling rig, and $19 million due to lower G&G and other expenses. These decreases were partially offset by higher exploratory dry hole costs of $15 million and higher amortization of undeveloped lease costs of $2 million.

Income Tax Expense

Income tax expense increased $195 million in 2003. The increase in tax expense was primarily due to higher pretax income of $1,001 million. In November 2003, the Government of Canada passed Bill C-48, which reduced the Canadian federal income tax rate for companies in the natural resource sector from 28 percent to 21 percent over a 5-year period beginning in 2003. As a result, in 2003, the Company recorded a benefit of $203 million related to the reduction in the Canadian federal income tax rate. The Company also recorded a net tax benefit of $27 million in 2003 related to the successful appeal of the 1996-1998 IRS tax audit. Additionally, the Company recorded higher tax benefits of $11 million in 2003 related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada. Substantially all of the increase in the tax benefit of the cross-border financing deduction from 2002 to 2003 was due to the strengthening of the Canadian dollar. This benefit is not expected to fluctuate in the future for reasons other than changes in exchange rate and debt levels. In 2003, the Company resolved all disputes under tax sharing agreements with certain former affiliates. As a result, during 2003, the Company recorded a $3 million decrease in income tax expense. The Company recorded lower tax benefits of $15 million related to the reduction in the Alberta provincial corporate income tax rate in Canada. Year 2002 included a tax benefit associated with the reversal of a tax valuation allowance of $27 million related to the sale of assets in the U.K. sector of the North Sea.

Legal Proceedings

The Company and numerous other oil and gas companies have been named as defendants in various lawsuits alleging violations of the civil False Claims Act. These lawsuits were consolidated during 1999 and 2000 for pre-trial proceedings by the United States Judicial Panel on Multidistrict Litigation in the matter of *In re Natural Gas Royalties Qui Tam Litigation*, MDL-1293, United States District Court for the District of Wyoming ("MDL-1293"). The plaintiffs contend that defendants underpaid royalties on natural gas and NGLs produced on federal and Indian lands through the use of below-market prices, improper deductions, improper measurement techniques and transactions with affiliated companies during the period of 1985 to the present. Plaintiffs allege that the royalties paid by defendants were lower than the royalties required to be paid under federal regulations and that the forms filed by defendants with the Minerals Management Service ("MMS") reporting these royalty payments were false, thereby violating the civil False Claims Act. The United States has intervened in certain of the MDL-1293 cases as to some of the defendants, including the Company. The plaintiffs and the intervenor have not specified in their pleadings the amount of damages they seek from the Company. On December 5, 2003, the United States Judicial Panel on Multidistrict Litigation entered an order transferring the cases alleging claims of below-market prices, improper deductions, and transactions with affiliated companies for further pre-trial proceedings and trial in *Wright v. AGIP*, 5:03CV264, United States District Court for the Eastern District of Texas, Texarkana Division. All parties are proceeding with pre-trial discovery, and the trial of these cases is scheduled to begin in February 2007. The cases alleging improper measurement techniques remain pending in MDL-1293, and motions to dismiss have been filed by the Company and other defendants and are pending before the Court.

Various administrative proceedings are also pending before the MMS of the United States Department of the Interior with respect to the valuation of natural gas produced by the Company on federal and Indian lands. In general, these proceedings stem from regular MMS audits of the Company's royalty payments over various periods of time and involve the interpretation of the relevant federal regulations. Most of these proceedings involve production volumes and royalties that are the subject of Natural Gas Royalties Qui Tam Litigation.

Based on the Company's present understanding of the various governmental and civil False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. The Company is also exploring the possibility of a settlement of these claims. Although there has been no formal demand for damages, the Company currently estimates, based on its communications with the intervenor, that the amount of underpaid royalties on onshore production claimed by the intervenor in these proceedings is approximately $76 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could be subject to double damages, civil monetary penalties and other sanctions, including a temporary suspension from bidding on and entering into future federal mineral leases and other federal contracts for a defined period of time. As an alternative to monetary penalties under the False Claims Act, the intervenor has informed the Company that it may seek the recovery of interest payments of approximately $95 million. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter.

The Company has also been named as a defendant in the lawsuit styled *UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al*, No. 98-854, filed in 1995 in the District Court in The Hague and currently pending in the Court of Appeal in The Hague, the Netherlands. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the

L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.5 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a Judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeal in The Hague issued an interim Judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. After receiving additional evidence from the parties, the Court of Appeals subsequently issued a ruling in favor of defendants. In an interim Judgment issued on December 18, 2003, the Court of Appeals found that defendants should not have assumed that they were extracting oil from the Q-1 Block, that Unocal was not entitled to compensation for any production occurring prior to 1992 and that damages, if any, would be limited to the proceeds Unocal would have received for oil extracted from the Q-1 Block, less the costs Unocal would have incurred to produce the oil from an existing well in the L16a Block. The Court of Appeals ordered that further evidence be presented to a court appointed expert to determine whether any damages had been suffered by Unocal. The Company and the other defendants are continuing to present evidence to the Court and vigorously assert defenses against these claims. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. Based on the information known to date, the Company believes that Unocal suffered no damages in excess of the costs of production and that the Company will incur no liability in this matter other than the costs of litigation. The Company has not established a reserve for this matter since it currently does not believe that an unfavorable outcome is probable.

The Company and its former affiliate, El Paso Natural Gas Company, have also been named as defendants in two class action lawsuits styled *Bank of America, et al. v. El Paso Natural Gas Company, et al.*, Case No. CJ-97-68, and *Deane W. Moore, et al. v. Burlington Northern, Inc., et. al.*, Case No. CJ-97-132, each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. Plaintiffs contend that defendants underpaid royalties from 1982 to the present on natural gas produced from specified wells in Oklahoma through the use of below-market prices, improper deductions and transactions with affiliated companies and in other instances failed to pay or delayed in the payment of royalties on certain gas sold from these wells. The plaintiffs seek an accounting and damages for alleged royalty underpayments, plus interest from the time such amounts were allegedly due. Plaintiffs additionally seek the recovery of punitive damages. The plaintiffs have not specified in their pleadings the amount of damages they seek from the Company. However, through pre-trial discovery, plaintiffs have provided defendants with alternative theories of recovery claiming monetary damages of up to $221 million in principal, plus $996 million in interest and unspecified punitive damages and attorney's fees. The Company believes it has substantial defenses to these claims and is vigorously asserting such defenses. The Company and El Paso Natural Gas Company have asserted contractual claims for indemnity against each other. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties are proceeding with pre-trial discovery. It is anticipated that the trial of this matter will be scheduled during 2005. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter.

The Company received notice on October 19, 2004 from the United States Department of Justice that it may be one of many potentially responsible parties under the Comprehensive Environmental Response, Compensation and Liability Act, as amended, with respect to the remediation of a site known as the Castex Systems, Inc. Oil Field Waste Disposal Site in Jefferson Davis Parish near Jennings, Louisiana. According to the Department of Justice, the remediation of the site has been completed under the supervision of the United States Environmental Protection Agency for a total cost of approximately $3 million. The Company has been informed that it may have contributed up to two and one-half percent (2.5%) of the liquid oil field waste and twelve percent (12%) of the solid oil field waste identified at the site. The Company has signed an agreement tolling the statute of limitations for a period of approximately three months and is currently investigating this matter to determine if it is liable for any portion of the remediation costs.

In addition to the foregoing, the Company and its subsidiaries are named defendants in numerous other lawsuits and named parties in numerous governmental and other proceedings arising in the ordinary course of business, including: claims for personal injury and property damage, claims challenging oil and gas royalty, ad valorem and severance tax payments, claims related to joint interest billings under oil and gas operating agreements, claims alleging mismeasurement of volumes and wrongful analysis of heating content of natural gas and other claims in the nature of contract, regulatory or employment disputes. None of the governmental proceedings involve foreign governments.

While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these legal proceedings and environmental matters through settlement or adverse judgment will not have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

At December 31, 2004, the Company's Consolidated Balance Sheet included reserves for legal proceedings of $84 million and environmental matters of $15 million. The accrual of reserves for legal and environmental matters is included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional loss, the amount of which is not currently estimable, in excess of the amounts currently accrued with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings and environmental matters will exceed current accruals by an amount that would have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

Other Matters

Recent Accounting Pronouncements

In January 2005, the Financial Accounting Standards Board ("FASB") issued SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29*. This statement, which addresses the measurement of exchanges of nonmonetary assets, is effective prospectively for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of this statement is not expected to impact the Company's consolidated financial position or results of operations.

In January 2005, the FASB issued SFAS No. 151, *Inventory Costs,* which is effective prospectively for inventory costs incurred during fiscal years beginning after June 15, 2005. SFAS No. 151 amends Accounting Research Bulletin No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs, and wasted materials should be recognized as current period charges. The adoption of this statement is not expected to impact the Company's consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (revised 2004) or SFAS No. 123(R), *Share-Based Payment.* This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company will adopt this statement on July 1, 2005 using the modified prospective application method described in the statement. Under the modified prospective application method, the Company will apply the standard to new awards and to awards modified, repurchased, or cancelled after the required effective date. Additionally, compensation cost for the unvested portion of awards outstanding as of the required effective date will be recognized as compensation expense as the requisite service is rendered after the required effective date. The adoption of this statement is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46, ("FIN 46"), *Consolidation of Variable Interest Entities.* FIN 46, as amended by FIN 46(R), provides guidance on how to identify a variable interest entity ("VIE"), and determine when the assets, liabilities, and results of operations of a VIE need to be included in a company's consolidated financial statements. FIN 46 also requires additional disclosures by primary beneficiaries and other significant variable interest holders in a VIE. The provisions of FIN 46 were effective immediately for all VIEs created after January 31, 2003. For VIEs created before February 1, 2003, the provisions of FIN 46, as amended, were effective on January 1, 2004. After evaluating this accounting pronouncement, the Company determined that it did not have any interests in any VIEs. Therefore, the adoption of FIN 46 did not have any impact on the Company's consolidated financial position, results of operations or cash flows.

Other Information

The Company's independent auditor, PricewaterhouseCoopers LLP ("PwC"), has recently notified the SEC, the Public Company Accounting Oversight Board and the Audit Committee of the Company's Board of Directors that certain non-audit work it previously performed in China for the Company and other companies has raised questions regarding PwC's independence with respect to its performance of audit services.

With respect to the Company, during fiscal years 2002, 2003 and 2004, PwC's affiliated firm in China performed tax calculation and return preparation services for a small number of employees of the Company's subsidiary in China. PwC's China affiliate received from the Company and remitted to the appropriate authorities on behalf of the Company's employees payments of the relevant taxes owed by the employees, which involved the handling of Company funds in the amount of approximately $232,000 in 2002, $340,000 in 2003 and $44,000 in 2004. The fees paid by the Company to PwC's China affiliate for the performance of all expatriate tax services were approximately $6,000 in 2002, $15,000 in 2003 and $8,000 in 2004. These expatriate tax services were discontinued during 2004.

PwC has informed the Company's Audit Committee that it does not believe its independence was impaired by the performance of tax payment services. The Company, in consultation with legal counsel, and the Company's Audit Committee independently reviewed the facts surrounding these services provided by PwC's China affiliate and do not believe that PwC's independence was impaired by the performance of tax calculations and return preparation services in light of the nature of the services, the size of the fees associated with the services and the fact that none of PwC's personnel who were involved in providing these tax services performed any audit or audit-related services for the Company.

Safe Harbor Cautionary Disclosure on Forward-Looking Statements

The Company, in discussions of its future plans, expectations, objectives and anticipated performance in periodic reports filed by the Company with the SEC (or documents incorporated by reference therein) may include projections or other forward-looking statements within the meaning of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 and Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by the words "expects," "anticipates," "intends," "plans," "believes," "should" and similar expressions. Projections and forward-looking statements are based on assumptions which the Company believes are reasonable, but are by their nature inherently uncertain. In all cases, there can be no assurance that such assumptions will prove correct or that projected events will occur, and actual results could differ materially from those projected. Some of the important factors that could cause actual results to differ from any such projections or other forward-looking statements follow.

Commodity Prices—Changes in natural gas, NGLs and crude oil prices (including basis differentials) from those assumed in preparing projections and forward-looking statements could cause the Company's actual financial results to differ materially from projected financial results and could also impact the Company's determination of proved reserves and the standardized measure of discounted future net cash flows relative to natural gas, NGLs and crude oil reserves. In addition, periods of sharply lower commodity prices could affect the Company's production levels could cause it to curtail capital spending projects and delay or defer exploration, exploitation or development projects, could render productive wells non-commercial earlier than in a higher price environment and could result in the Company recognizing for Generally Accepted Accounting Principles purposes an impairment of unamortized capital costs.

Projections relating to the price received by the Company for natural gas and NGLs also rely on assumptions regarding the availability and pricing of transportation to the Company's key markets. In particular, the Company has contractual arrangements for the transportation of natural gas from the San Juan Basin eastward to Eastern and Midwestern markets or to market hubs in Texas, Oklahoma and Louisiana. The natural gas price received by the Company could be adversely affected by any constraints in pipeline capacity to serve these markets. These and other commodity price risks that could cause actual results to differ from projections and forward-looking statements are further described in Part II, "Qualitative and Quantitative Disclosure About Market Risk-Commodity Risk."

Exploration and Production Risk—The Company's business is subject to all of the risks and uncertainties normally associated with the exploration for and development and production of natural gas, NGLs and crude oil, including uncertainties as to the presence, size and recoverability of hydrocarbons. The exploration for natural gas and crude oil is a high-risk business in which significant numbers of dry holes, completion and production difficulties and high associated costs can be incurred in the process of seeking commercial discoveries and placing them on production.

The process of estimating quantities of proved reserves is inherently uncertain and requires making subjective engineering, geological, geophysical and economic assumptions. In this regard, changes in the economic conditions (including commodity prices) or operating conditions (including, without limitation, exploration, development and production costs and expenses and drilling and production results from exploration and development activity) could cause the Company's estimated proved reserves or production to differ from those included in any such forward-looking statements or projections. Reserves which require the use of improved recovery techniques for production are included in proved reserves if supported by a suitable analogy, a successful pilot project or the operation of an installed program. There are many risks inherent in developing and implementing improved recovery techniques which can cause a pilot project to be unsuccessful.

In addition, the Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment as well as to dismantle and abandon plants at the end of oil and gas production operations. Estimating the costs of these obligations requires management to make estimates and judgments regarding timing, existence of a liability as well as what constitutes adequate restoration. Increases in the estimated costs of decommissioning and abandoning a developed property or production facilities above previously forecasted levels could cause the Company's estimated proved reserves to decrease from those included in forward-looking statements.

Projecting future natural gas, NGLs and crude oil production is imprecise. Producing oil and gas reservoirs eventually have declining production rates. Projections of production rates rely on certain assumptions regarding historical production patterns in the area or formation tests for a particular producing horizon. Actual production rates could differ materially from such projections. Production rates depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate. In addition, OPEC countries in which the Company has producing properties, such as Algeria, could subject the Company to periods of curtailed production due to governmental mandated cutbacks when world oil market demand is weak.

Another major factor affecting the Company's production is its ability to replace depleting reservoirs with new reserves through acquisition, exploration or development programs. Exploration success is extremely difficult to predict with certainty, particularly over the short term where the timing and extent of successful results vary widely. Over the long term, the ability to replace reserves depends not only on the Company's ability to locate crude oil, NGLs and natural gas reserves, but on the cost of finding and developing such reserves. Moreover, development of any particular exploration or development project may not be justified because of the commodity price environment at the time or because of the Company's finding and development costs for such project. No assurances can be given as to the level or timing of success that the Company will be able to achieve in acquiring or finding and developing additional reserves.

Projections relating to the Company's production and financial results rely on certain assumptions about the Company's continued success in its acquisition and asset rationalization programs and in its cost management efforts.

The Company's drilling operations are subject to various hazards common to the oil and gas industry, including weather conditions, explosions, fires, and blowouts, which could result in damage to or destruction of oil and gas wells or formations, production facilities and other property and injury to people. They are also subject to the additional hazards of marine operations, such as capsizing, collision and damage or loss from severe weather conditions.

Goodwill—The Company accounts for goodwill in accordance with SFAS No. 142, Goodwill and other Intangible Assets, and is required to make an annual impairment assessment in lieu of periodic amortization. The impairment assessment requires the Company to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. Although the Company bases its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar or depressed natural gas, NGLs and crude oil prices could lead to an impairment of goodwill in future periods.

Development Risk—A significant portion of the Company's development plans involve large projects in Canada, Algeria, the East Irish Sea, China, Ecuador, Wyoming, North Dakota and other areas. A variety of factors affect the timing and outcome of such projects including, without limitation, approval by the other parties owning working interests in the project, receipt of necessary permits and approvals by applicable governmental agencies, access to surface locations and facilities, opposition by non-government organizations and local indigenous communities, the availability, costs and performance of the necessary drilling equipment and infrastructure, drilling risks, operating hazards, unexpected cost increases and technical difficulties in constructing, modifying and operating equipment, plants and facilities, manufacturing and delivery schedules for critical equipment and arrangements for the gathering and transportation of the produced hydrocarbons.

Foreign Operations Risk—The Company's operations outside of the U.S. are subject to risks inherent in foreign operations, including, without limitation, the loss of revenue, property and equipment from hazards such as expropriation, nationalization, war, insurrection, acts of terrorism and other political risks, increases in taxes and governmental royalties, renegotiation or abrogation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations, world economic cycles, restrictions or quotas on production and commodity sales, limited market access and other uncertainties arising out of foreign government sovereignty over the Company's international operations. Laws and policies of the U.S. affecting foreign trade and taxation may also adversely affect the Company's international operations.

The Company's ability to market natural gas, NGLs and crude oil discovered or produced in its foreign operations, and the price the Company could obtain for such production, depends on many factors beyond the Company's control, including ready markets for natural gas, NGLs and crude oil, the proximity and capacity of pipelines and other transportation facilities, fluctuating demand for crude oil and natural gas, the availability and cost of competing fuels, and the effects of foreign governmental regulation of oil and gas production and sales. Pipeline and processing facilities do not exist in certain areas of exploration and, therefore, any actual sales of the Company's production could be delayed for extended periods of time until such facilities are constructed.

Competition—The Company actively competes for property acquisitions, exploration leases and sales of natural gas, NGLs and crude oil, frequently against companies with substantially larger financial and other resources. In its marketing activities, the Company competes with numerous companies for gas purchasing and processing contracts and for natural gas and NGLs at several stages in the distribution chain. Competitive factors in the Company's business include price, contract terms, quality of service, pipeline access, transportation discounts and distribution efficiencies.

Legal and Regulatory Risk—The Company's operations are affected by foreign, national, state and local laws and regulations. Compliance with these regulations is often difficult and costly and non-compliance could subject the

Company to material administrative, civil or criminal penalties, or other liabilities. Restrictions on production, price or gathering rate controls, changes in taxes, royalties and other amounts payable to governments or governmental agencies and other changes in or litigation arising under laws and regulations, or interpretations thereof, could have a significant effect on the Company's operations or financial results. The Company's operations in some geographic areas may be negatively impacted by legal proceedings, the actions of national, state and local governments, and the actions of non-governmental organizations that delay, restrict or prevent the Company's access to surface locations for natural gas and crude oil exploration and production activities. The Company's operations also may be negatively impacted by laws, regulations and legal proceedings pertaining to the valuation and measurement of natural gas, crude oil and NGLs and payment of royalties from such sales. Existing litigation involving the valuation and measurement of natural gas, crude oil and NGLs and payment of royalties from such sales is described in Note 14 of the Notes to Consolidated Financial Statements. Other legal and regulatory risks that could cause actual results to differ from projections and other forward-looking statements are described in Part I, "Other Matters."

Political and Security Risk—Domestic and international political and security risks, including changes in government, seizure of property, civil unrest, armed hostilities and acts of terrorism, could have a significant effect on the Company's operations or financial results.

Environmental Regulations and Liabilities—The Company's operations are subject to various foreign, national, state and local laws and regulations covering the discharge of material into, and protection of, the environment. Such regulations and liability for remedial actions under environmental regulations affect the costs of planning, designing, operating and abandoning facilities. The Company expends considerable resources, both financial and managerial, to comply with environmental regulations and permitting requirements. Although the Company believes that its operations and facilities are in substantial compliance with applicable environmental laws and regulations, risks of substantial costs and liabilities are inherent in crude oil and natural gas operations. Moreover, it is possible that other developments, such as increasingly strict environmental laws, regulations and enforcement, and claims for damage to property or persons resulting from the Company's current or discontinued operations, could result in substantial costs and liabilities in the future.

While the Company maintains insurance coverage for spills, pollutions and certain other environmental risks, it is not fully insured against all such risks. Because regulatory requirements frequently change and may become more stringent, and environmental costs and liabilities are inherent in the Company's operations, there can be no assurance that material costs and liabilities will not be incurred in the future or that the Company's insurance will be sufficient to cover any such costs or liabilities. Such costs may result in increased costs of operations and acquisitions and decrease production.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on our assessment, management has concluded that, as of December 31, 2004, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited our assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, as stated in their report which appears on page 39.

Bobby S. Shackouls
Chairman of the Board, President and
Chief Executive Officer

Steven J. Shapiro
Executive Vice President and Chief
Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
of Burlington Resources Inc.:

We have completed an integrated audit of Burlington Resources Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, cash flows and stockholders' equity present fairly, in all material respects, the financial position of Burlington Resources Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 10 to the consolidated financial statements, on January 1, 2003, the Company changed its method of accounting for its asset retirement obligations in connection with its adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the Management Report on Internal Control Over Financial Reporting appearing under Item 7, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2005

FINANCIAL STATEMENTS AND SUPPLEMENTARY FINANCIAL INFORMATION
BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31,	2004	2003	2002
	(In Millions, Except per Share Amounts)		
REVENUES	**$5,618**	**$4,311**	**$2,968**
COSTS AND OTHER INCOME—NET			
Taxes Other than Income Taxes	260	187	123
Transportation Expense	453	408	354
Operating Costs	587	475	467
Depreciation, Depletion and Amortization	1,137	927	833
Exploration Costs	258	252	286
Impairment of Oil and Gas Properties	90	63	—
Administrative	215	164	161
Interest Expense	282	260	274
(Gain) / Loss on Disposal of Assets	13	(8)	(68)
Other Expense (Income)—Net	19	13	(31)
Total Costs and Other Income—Net	**3,314**	**2,741**	**2,399**
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	2,304	1,570	569
Income Tax Expense	777	310	115
Income Before Cumulative Effect of Change in Accounting Principle	1,527	1,260	454
Cumulative Effect of Change in Accounting Principle—Net	—	(59)	—
Net Income	**$1,527**	**$1,201**	**$ 454**
EARNINGS PER COMMON SHARE			
Basic			
Before Cumulative Effect of Change in Accounting Principle	$ 3.90	$ 3.17	$ 1.13
Cumulative Effect of Change in Accounting Principle—Net	—	(0.15)	—
Net Income	$ 3.90	$ 3.02	$ 1.13
Diluted			
Before Cumulative Effect of Change in Accounting Principle	$ 3.86	$ 3.15	$ 1.13
Cumulative Effect of Change in Accounting Principle—Net	—	(0.15)	—
Net Income	**$ 3.86**	**$ 3.00**	**$ 1.13**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET

December 31,	2004	2003
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 2,179	$ 757
Accounts Receivable	994	605
Inventories	124	81
Other Current Assets	158	74
	3,455	1,517
Oil and Gas Properties (Successful Efforts Method)	17,943	15,962
Other Properties	1,544	1,381
	19,487	17,343
Less: Accumulated Depreciation, Depletion and Amortization	8,454	7,032
Properties—Net	11,033	10,311
Goodwill	1,054	982
Other Assets	202	185
Total Assets	**$15,744**	**$12,995**
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 1,182	$ 714
Taxes Payable	264	43
Accrued Interest	61	61
Dividends Payable	33	30
Current Maturities of Long-term Debt	2	—
Other Current Liabilities	57	43
	1,599	891
Long-term Debt	3,887	3,873
Deferred Income Taxes	2,396	1,948
Other Liabilities and Deferred Credits	851	762
Commitments and Contingent Liabilities (Note 14)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.01 per Share (Authorized 75,000,000 Shares; No Shares Issued)	—	—
Common Stock, Par Value $.01 per Share (Authorized 650,000,000 Shares; Issued 482,376,870 and 482,377,376 Shares for 2004 and 2003, respectively)	5	5
Paid-in Capital	3,973	3,943
Retained Earnings	4,163	2,761
Deferred Compensation—Restricted Stock	(14)	(10)
Accumulated Other Comprehensive Income	1,092	655
Cost of Treasury Stock (94,435,401 and 87,079,770 Shares for 2004 and 2003, respectively)	(2,208)	(1,833)
Stockholders' Equity	7,011	5,521
Total Liabilities and Stockholders' Equity	**$15,744**	**$12,995**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

Year Ended December 31,	2004	2003	2002
		(In Millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,527	$ 1,201	$ 454
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,137	927	833
Deferred Income Taxes	371	150	39
Exploration Costs	258	252	286
Impairment of Oil and Gas Properties	90	63	—
(Gain)/Loss on Disposal of Assets	13	(8)	(68)
Changes in Derivative Fair Values	(5)	(5)	32
Cumulative Effect of Change in Accounting Principle—Net	—	59	—
Working Capital Changes			
Accounts Receivable	(365)	(28)	(117)
Inventories	(40)	(26)	2
Other Current Assets	(25)	(15)	(17)
Accounts Payable	278	(4)	138
Taxes Payable	188	(9)	43
Accrued Interest	—	(1)	4
Other Current Liabilities	18	—	(8)
Changes in Other Assets and Liabilities	(9)	(17)	(72)
Net Cash Provided by Operating Activities	3,436	2,539	1,549
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Properties	(1,582)	(1,899)	(1,851)
Proceeds from Sales and Other	(25)	4	1,180
Net Cash Used in Investing Activities	(1,607)	(1,895)	(671)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-term Debt	41	—	454
Reduction in Long-term Debt	(41)	(75)	(879)
Dividends Paid	(122)	(85)	(139)
Common Stock Purchases	(518)	(356)	—
Common Stock Issuances	153	128	13
Other	(1)	(3)	2
Net Cash Used in Financing Activities	(488)	(391)	(549)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	81	61	(2)
Increase in Cash and Cash Equivalents	1,422	314	327
Cash and Cash Equivalents			
Beginning of Year	757	443	116
End of Year	$ 2,179	$ 757	$ 443

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation — Restricted Stock	Accumulated Other Comprehensive Income (Loss)	Cost of Treasury Stock	Stockholders' Equity
				(In Millions, Except Share Data)			
December 31, 2001	$5	$3,941	$1,332	$ (9)	$ (106)	$(1,638)	$3,525
Comprehensive Income (Loss)							
Net Income			454				454
Foreign Currency Translation					34		34
Hedging Activities					(86)		(86)
Minimum Pension Liability					(6)		(6)
Comprehensive Income (Loss)			454		(58)		396
Cash Dividends Declared ($0.28 per Share)			(111)				(111)
Stock Option Activity		(3)				16	13
Issuance of Restricted Stock				(9)		9	—
Amortization of Restricted Stock				9			9
December 31, 2002	5	3,938	1,675	(9)	(164)	(1,613)	3,832
Comprehensive Income							
Net Income			1,201				1,201
Foreign Currency Translation					802		802
Hedging Activities					11		11
Minimum Pension Liability					6		6
Comprehensive Income			1,201		819		2,020
Cash Dividends Declared ($0.29 per Share)			(115)				(115)
Common Stock Purchases (14,829,980 Shares)						(361)	(361)
Stock Option Activity		5				129	134
Issuance of Restricted Stock				(12)		12	—
Amortization of Restricted Stock				11			11
December 31, 2003	5	3,943	2,761	(10)	655	(1,833)	5,521
Comprehensive Income							
Net Income			1,527				1,527
Foreign Currency Translation					396		396
Hedging Activities					41		41
Comprehensive Income			1,527		437		1,964
Cash Dividends Declared ($0.32 per Share)			(125)				(125)
Common Stock Purchases (14,358,000 Shares)						(522)	(522)
Stock Option Activity		30				132	162
Issuance of Restricted Stock				(15)		15	—
Amortization of Restricted Stock				11			11
December 31, 2004	**$5**	**$3,973**	**$4,163**	**$(14)**	**$1,092**	**$(2,208)**	**$7,011**

See accompanying Notes to Consolidated Financial Statements.

1. Accounting Policies

Nature of Business

Burlington Resources Inc. ("BR") is among the world's largest independent oil and gas companies and holds one of the industry's leading positions in North American natural gas reserves and production. BR conducts exploration, production and development operations in the U.S., Canada, the United Kingdom, Africa, China and South America. Its extensive North American lease holdings extend from the U.S. Gulf Coast to Northeast British Columbia and Northern Alberta in Canada. BR is a holding company and its principal subsidiaries include Burlington Resources Oil & Gas Company LP, The Louisiana Land and Exploration Company ("LL&E"), Burlington Resources Canada Ltd. (formerly known as Poco Petroleums Ltd.), Burlington Resources Canada (Hunter) Ltd. (formerly known as Canadian Hunter Exploration Ltd.) ("Hunter"), and their affiliated companies (collectively, "the Company").

Principles of Consolidation and Reporting

The consolidated financial statements of the Company include the accounts of BR and its majority-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. Investments in entities in which the Company has a significant ownership interest, generally 20 to 50 percent, or otherwise does not exercise control, are accounted for using the equity method. Under the equity method, the investments are stated at cost plus the Company's equity in undistributed earnings and losses. The consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income or stockholders' equity.

Stock Split ("split")

All prior period common stock and applicable share and per share amounts have been retroactively adjusted to reflect a 2-for-1 split of the Company's Common Stock effective June 1, 2004.

Cash and Cash Equivalents

All short-term investments purchased with a maturity of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates market value.

Inventories

Inventories of materials, supplies and products are valued at the lower of average cost or market. Inventories consisted of the following.

December 31,	**2004**	**2003**
	(In Millions)	
Materials and supplies	$ 99	$70
Product inventory	25	11
Inventories	$124	$81

Properties

Proved

Oil and gas properties are accounted for using the successful efforts method. Under this method, all development costs and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

The Company evaluates the impairment of its proved oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value if the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon reserves using prices and costs consistent with those used for internal decision making. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with the New York Mercantile Exchange pricing and adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Given that spot hydrocarbon market prices are subject to volatile changes, it is the Company's opinion that a long-term look at market prices will lead to a more appropriate valuation of long-term assets.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major replacements and renewals are capitalized. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. See Note 10 of Notes to Consolidated Financial Statements.

Unproved

Unproved properties consist of costs incurred to acquire unproved leases ("lease acquisition costs") as well as costs incurred to acquire unproved reserves. Unproved lease acquisition costs are capitalized and amortized on a composite basis, based on past success, experience and average lease-term lives. Unamortized lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The book value of the Company's unproved reserves, which were acquired in connection with business acquisitions, was determined using the same methods, after adjusting for risks, that were used to value the proved reserves acquired in the same acquisition. Because these reserves did not meet the strict definition of proved reserves, the related costs were not classified as proved properties. As the unproved reserves are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved reserves for impairment annually by comparing book value to fair value, which is determined using discounted estimates of future cash flows. See Note 16 of Notes to Consolidated Financial Statements.

Exploration

Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after completing or drilling the well, however, in certain situations determination cannot be made when drilling is completed. The Company defers capitalized exploratory costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells in progress as long as development is underway, is firmly planned for the near future or the necessary approvals are actively being sought. For all other exploratory wells, determination is made within one year from the date drilling and other necessary activities have been completed. If a determination cannot be made after one year, all costs associated with the well are expensed.

Other

Other properties include gas plants, pipelines, buildings, data processing and telecommunications equipment, office furniture and equipment and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets.

Goodwill

Goodwill represents the excess of the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed. The Company accounts for its goodwill in accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets,* which requires the Company to test goodwill for impairment annually or whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, rather than amortize.

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company's net interest. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, NGLs and crude oil are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, the Company maintains a minimum amount of product inventory in storage. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than it is entitled, the underproduction is recorded as a receivable. At December 31, 2004 and 2003, the Company had a net gas imbalance payable of $11 million and a net gas imbalance receivable of $19 million, respectively, of which $58 million and $69 million is recorded in Accounts Receivable and Accounts Payable, respectively, on the Company's Consolidated Balance Sheet at December 31, 2004.

The Company utilizes buy/sell or exchange contracts to transport its crude oil from producing areas to a market center, typically Cushing, Oklahoma. The Company accounts for these transactions on a net basis in its Consolidated Statement of Income.

Royalty Payable

It is the Company's policy to calculate and pay royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Accounts Payable on the Company's Consolidated Balance Sheet.

Foreign Currency Translation

The assets, liabilities and operations of BR's Canadian operating subsidiaries are measured using the Canadian dollar as the functional currency. These assets and liabilities are translated into United States ("U.S.") dollars at end-of-period exchange rates. Gains and losses related to translating these assets and liabilities are recorded in Accumulated Other Comprehensive Income. At December 31, 2004 and 2003, the balances in Accumulated Other Comprehensive Income related to foreign currency translation were gains of $1,072 million and $676 million, respectively. Revenue and expenses are translated into U.S. dollars at the average exchange rates in effect during the period. The assets, liabilities and results of operations of BR's International operating subsidiaries are measured using the U.S. dollar as the functional currency. For International subsidiaries where the U.S. dollar is the functional currency, all foreign currency denominated assets and liabilities are remeasured into U.S. dollars at end-of-period exchange rates. Inventories, prepaid expenses and properties are exceptions to this policy and are remeasured at historical rates. Foreign currency revenues and expenses are remeasured at average exchange rates in effect during the year. Exceptions to this policy include all expenses related to balance sheet amounts that are remeasured at historical exchange rates. Exchange gains and losses arising from remeasured foreign currency denominated monetary assets and liabilities are included in Other Expense (Income) — Net in the Consolidated Statement of Income. Included in net income for the years ended December 31, 2004, 2003 and 2002 are exchange gains of $5 million and exchange losses of $7 million and $1 million, respectively.

Commodity Hedging Contracts and Other Derivatives

The Company enters into derivative contracts, primarily options and swaps, to hedge future natural gas and crude oil production in order to mitigate the risk of market price fluctuations. The Company also enters into derivative contracts to mitigate the risk of foreign currency exchange and interest rate fluctuations. All derivatives are recognized on the balance sheet and measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in the fair value of the derivative are recognized currently in earnings. If the derivative qualifies for hedge accounting, changes in the fair value of the derivative are either recognized in income along with the corresponding change in fair value of the item being hedged for fair-value hedges or deferred in other comprehensive income to the extent the hedge is effective for cash-flow hedges. To qualify for hedge accounting, the derivative must qualify as either a fair-value, cash-flow or foreign-currency hedge.

The hedging relationship between the hedging instruments and hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively if and when a hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of its derivative instruments. Gains and losses deferred in Accumulated Other Comprehensive Income related to cash-flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. Adjustment to the carrying amounts of hedged items is discontinued in instances where the related fair-value hedging instrument becomes ineffective. The balance in the fair-value hedge adjustment account is recognized in income when the hedged item is sold. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the related hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues and are included in realized prices in the period that the hedged item is sold. Gains and losses on hedging instruments which represent hedge ineffectiveness and gains and losses on derivative instruments which do not qualify for hedge accounting are included in revenues in the period in which they occur. The resulting cash flows are reported as cash flows from operating activities.

Credit and Market Risks

The Company manages and controls market and counterparty credit risk through established formal internal control procedures which are reviewed on an ongoing basis. In the normal course of business, collateral is not required for financial instruments with credit risk. The Company uses the specific identification method of providing allowances for doubtful accounts.

Income Taxes

Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities. Tax credits are accounted for under the flow-through method, which reduces the provision for income taxes in the year the tax credits are earned. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Treasury Stock

The Company follows the weighted-average-cost method of accounting for treasury stock transactions.

Stock-based Compensation

At December 31, 2004, the Company has three stock-based employee compensation plans, which are described in Note 12 of Notes to Consolidated Financial Statements. The Company uses the intrinsic value based method of accounting for stock-based compensation, as prescribed by Accounting Principles Board Opinion No. 25 and related interpretations. Under this method, the Company records no compensation expense for stock options granted when the exercise price for options granted is equal to the fair market value of the Company's Common Stock on the date of the grant.

The weighted average fair values of options granted during the years 2004, 2003 and 2002 were $5.50, $5.43 and $5.42, respectively. The fair values of employee stock options were calculated using the Black-Scholes stock option valuation model that has been modified to include dividends since the Company has historically paid dividends. Additionally, the Company uses an expected term for stock options rather than the contractual term since they are non-transferable and are typically exercised prior to expiration. The following weighted average assumptions were used for grants in 2004, 2003 and 2002: stock price volatility of 26 percent, 32 percent and 31 percent, respectively; risk free rate of return ranging from 2 percent to 4 percent; dividend yields of 0.89 percent, 1.18 percent and 1.43 percent, respectively; and an expected term of 3 to 5 years.

The following table illustrates the effect on net income and earnings per share had the Company applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation,* to its stock-based employee compensation.

Year Ended December 31,	**2004**	**2003**	**2002**
	(In Millions, Except per Share Amounts)		
Net income—as reported	$1,527	$1,201	$ 454
Less: pro forma stock based employee compensation cost, after tax (unaudited)	10	10	11
Net income—pro forma (unaudited)	$1,517	$1,191	$ 443
Basic EPS—as reported	$ 3.90	$ 3.02	$ 1.13
Basic EPS—pro forma (unaudited)	3.87	2.99	1.11
Diluted EPS—as reported	3.86	3.00	1.13
Diluted EPS—pro forma (unaudited)	$ 3.84	$ 2.98	$ 1.10

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Earnings Per Common Share ("EPS")

Basic EPS is computed by dividing income available to common stockholders by the weighted-average number of common shares outstanding for the period. The weighted average number of common shares outstanding for computing basic EPS was 392 million, 398 million and 402 million for the years ended December 31, 2004, 2003 and 2002, respectively. Diluted EPS reflects the potential dilution that could occur if contracts to issue common stock and related stock options were exercised. The weighted average number of common shares outstanding for computing diluted EPS, including dilutive stock options, was 395 million, 400 million and 404 million for the years ended December 31, 2004, 2003 and 2002, respectively. All shares attributable to outstanding options were dilutive for the year ended December 31, 2004. For the years ended December 31, 2003 and 2002, approximately 2 million and 8 million shares, respectively, attributable to the assumed exercise of outstanding options were excluded from the calculation of diluted EPS because the effect was antidilutive. The Company has no preferred stock affecting EPS, and therefore, no adjustments related to preferred stock were made to reported net income in the computation of EPS.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas, NGLs and crude oil reserves and related cash flow estimates used in impairment tests of goodwill and other long-lived assets, estimates of future development, income taxes, dismantlement and abandonment costs, estimates relating to certain natural gas, NGLs and crude oil revenues and expenses as well as estimates of expenses related to legal, environmental and other contingencies. Actual results could differ from those estimates.

2. Property Acquisitions and Divestitures

Property Acquisitions

In May 2003, the Company purchased an additional 50 percent interest in CLAM Petroleum B.V. ("CLAM") for approximately $100 million, including cash acquired at closing of $25 million, resulting in a total purchase price for the common equity of approximately $75 million. The Company owned 50 percent of CLAM prior to the acquisition and had accounted for its interest under the equity method of accounting. Effective on the date of acquisition, the Company began consolidating CLAM's financial results.

Divestitures

During 2002, after announcing in late 2001 its intent to sell properties, the Company completed the sale of a processing facility and other non-core, non-strategic properties that consisted of high cost structure, high production volume decline rates and limited growth opportunities. As a result of this divestiture program, the Company generated proceeds, before post-closing adjustments, of approximately $1.2 billion and recognized a net pretax gain of $68 million in 2002. The Company used a portion of the proceeds generated from property sales to retire debt and for general corporate purposes.

3. Accounts Receivable

Accounts receivable consisted of the following.

December 31,	**2004**	**2003**
	(In Millions)	
Natural gas, NGLs and crude oil revenue sales	$ 848	$508
Joint interest billings	99	93
Income tax receivable	35	—
Other	25	17
	1,007	618
Less: allowance for doubtful accounts	13	13
Accounts receivable	$ 994	$605

4. Goodwill

The entire goodwill balance of $1,054 million at December 31, 2004, which is not deductible for tax purposes, is related to the Company's acquisition of Hunter in December 2001. With the acquisition of Hunter, the Company gained Hunter's significant interest in Canada's Deep Basin, North America's third-largest natural gas field, increased its critical mass and enhanced its position as a leading North American natural gas producer. The Company also obtained the exploration expertise of Hunter's workforce, gained additional cost optimization, increased purchasing power and gained greater marketing flexibility in optimizing sales and accessing key market information. The goodwill was assigned to the Company's Canadian reporting unit which includes all of the Company's Canadian subsidiaries.

The provisions of SFAS No. 142 require that a two-step impairment test be performed annually or whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. The first step of the test for impairment compares the book value of the Company's reporting unit to its estimated fair value. The second step of the goodwill impairment test, which is only required when the net book value of the reporting unit exceeds the fair value, compares the implied fair value of goodwill to its book value to determine if an impairment is required.

The Company performed step one of its annual goodwill impairment test in the fourth quarter of 2004 and determined that the fair value of the Company's Canadian reporting unit exceeded its net book value as of September 30, 2004. Therefore, step two was not required.

The fair value of the Company's Canadian reporting unit was determined using a combination of the income approach and the market approach. Under the income approach, the Company estimated the fair value of the reporting unit based on the present value of expected future cash flows. Under the market approach, the Company estimated the fair value based on market multiples of reserves and production for comparable companies as well as recent comparable transactions.

The income approach is dependent on a number of factors including estimates of forecasted revenue and costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar, or depressed natural gas, NGLs and crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. In the market approach, the Company makes certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although the Company based its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. In 2004, the Company used a professional valuation services firm to assist in preparing its annual valuation of goodwill.

The following table reflects the changes in the carrying amount of goodwill during the year as it relates to the Canadian reporting unit.

	(In Millions)
December 31, 2003	$ 982
Changes in foreign exchange rates during the period	72
December 31, 2004	$1,054

5. Oil and Gas and Other Properties

Oil and gas properties consisted of the following.

December 31,	**2004**	**2003**
	(In Millions)	
Proved properties	$16,662	$14,588
Less: Accumulated depreciation, depletion and amortization	7,882	6,573
Proved properties—net	8,780	8,015
Unproved properties		
Leasehold acquisition costs	536	495
Unproved reserves	745	879
Less: Accumulated amortization	152	97
Unproved properties—net	1,129	1,277
Oil and gas properties—net	$ 9,909	$ 9,292

The following table reflects the net changes in capitalized exploratory well costs pending proved reserve determination.

	2004	**2003**	**2002**
	(In Millions)		
Balance at January 1,	$ 29	$30	$19
Additions	18	8	19
Reclassifications to proved properties	(10)	(2)	(7)
Charged to expense	(14)	(7)	(1)
Balance at December 31,	$ 23	$29	$30
Capitalized less than one year since completion of drilling	$ 22		
Capitalized more than one year since completion of drilling (1)	$ 1		

(1) At December 31, 2004, the Company had deferred costs related to one well that has been completed for more than a year while the Company has actively been pursuing the necessary permits and pipeline connection.

Other properties consisted of the following.

December 31,	**Depreciable Life-Years**	**2004**	**2003**
		(In Millions)	
Plants and pipeline systems	10-20	$1,139	$1,018
Land, buildings, improvements and furniture and fixtures	0-40	139	128
Data processing and telecommunications equipment	3-7	184	159
Other	3-15	82	76
		1,544	1,381
Less: Accumulated depreciation		420	362
Other properties—net		$1,124	$1,019

6. Accounts Payable

Accounts payable consisted of the following.

December 31,	2004	2003
	(In Millions)	
Trade payables	$ 89	$ 67
Accrued expenses	828	478
Revenues and royalties payable to others	192	98
Accrued payroll	56	44
Other	17	27
Accounts payable	$1,182	$714

7. Income Taxes

The jurisdictional components of income before income taxes and cumulative effect of change in accounting principle follow.

Year Ended December 31,	2004	2003	2002
		(In Millions)	
Domestic	$1,357	$ 983	$548
Foreign	947	587	21
Total	$2,304	$1,570	$569

The provision for income taxes follows.

Year Ended December 31,	2004	2003	2002
		(In Millions)	
Current			
Federal	$171	$ 84	$ 37
State	43	9	11
Foreign	192	67	28
	406	160	76
Deferred			
Federal	175	85	63
State	(4)	6	4
Foreign	200	59	(28)
	371	150	39
Total	$777	$310	$115

Reconciliation of the federal statutory income tax rate to the effective income tax rate follows.

Year Ended December 31,	2004	2003	2002
U.S. statutory rate	35.0%	35.0%	35.0%
State income taxes (net of federal benefit)	1.0	0.6	1.7
Taxes on foreign income in excess of U.S. statutory rate	3.6	3.9	9.4
Effect of change in foreign income tax rate(1)	(2.9)	(13.6)	(2.3)
Section 29 tax credits(2)	(0.4)	(1.7)	(0.2)
Cross-border financing benefit(3)	(4.5)	(6.2)	(15.1)
Other(4)	1.9	1.7	(8.4)
Effective rate	33.7%	19.7%	20.1%

(1) In 2003, the government of Canada passed Bill C-48 that reduced the Canadian federal income tax rate for companies in the natural resource sector. The rate reduction takes effect over a five-year period from 2003 to 2007 and resulted in benefits to the Company of $23 million (−1.0%) and $203 million (−12.9%) in 2004 and 2003, respectively. The Company also recorded a benefit of $45 million (−1.9%), $11 million (−0.7%) and $26 million (−4.5%) in 2004, 2003 and 2002, respectively, due to reductions in the Alberta provincial corporate income tax rate in Canada. In 2002, the Company recorded an expense of $12 million (2.2%) related to an increase in the U.K.'s income tax rate.

(2) In 2004, a tax benefit associated with Section 29 Tax Credits was provided in the amount of $10 million (−0.4%) as a result of the finalization of the 1999-2000 federal income tax audits. In 2003, a tax benefit associated with Section 29 Tax Credits was provided in the amount of $27 million (−1.7%) as a result of an appeal proceeding related to the 1996-1998 income tax audits. In 2002, the tax benefit associated with Section 29 Tax Credits was reduced by $16 million (2.9%) as a result of the 1996-1998 federal income tax audits.

(3) The Company recorded benefits of $104 million, $97 million and $86 million in 2004, 2003 and 2002, respectively, related to interest deductions allowed in both the U.S. and Canada. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada.

(4) In 2004, the Company recorded a U.S. tax liability of $26 million (1.1%) related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. in 2005 under the one-time provisions of the American Jobs Creation Act of 2004. In 2002, this rate primarily consisted of the reversal of a $27 million (−4.8%) tax valuation reserve related to the sale of assets in the U.K. Sector of the North Sea.

Deferred income tax liabilities (assets) follow.

December 31,	**2004**	**2003**
	(In Millions)	
Deferred income tax liabilities		
Property, plant and equipment	$2,175	$1,972
Financial accruals and other	590	391
	2,765	2,363
Deferred income tax assets		
Alternative minimum tax ("AMT") credit carryforward	(161)	(277)
Foreign net operating loss carryforward	(171)	(150)
Commodity hedging contracts and other derivatives	13	(13)
	(319)	(440)
Less: valuation allowance	15	25
Deferred income taxes	$2,461	$1,948

At December 31, 2004, $48 million of the deferred income tax liability is classified as current and is included in Taxes Payable on the Company's Consolidated Balance Sheet. Also, $17 million of the deferred income tax liability related to income tax reserves is included in Other Liabilities and Deferred Credits. The net deferred income tax liabilities at December 31, 2004 and 2003 include deferred state income tax liabilities of approximately $51 million and $56 million, respectively. The net deferred income tax liabilities also include foreign tax liabilities of approximately $1,872 million and $1,564 million at December 31, 2004 and 2003, respectively.

No deferred U.S. income tax liability has been recognized on undistributed earnings of certain foreign subsidiaries as they have been deemed permanently invested outside the U.S., and it is not practicable to estimate the deferred tax liability related to such undistributed earnings. At December 31, 2004, undistributed earnings for which a U.S. deferred income tax liability has not been recognized total $1,079 million. The Company plans to repatriate $500 million of eligible foreign earnings to the U.S. Company in 2005 under the one-time provisions of the American Jobs Creation Act of 2004. Included in Taxes Payable at December 31, 2004 are accrued U.S. taxes of $26 million related to this planned repatriation. Not included in undistributed earnings at December 31, 2004 are permanent differences of $875 million that would result in taxable income in the U.S. if an amount greater than the retained earnings of the Company's Canadian subsidiaries was distributed to the U.S.

The AMT credit carryforward, related primarily to Section 29 Tax Credits, is available to offset future federal income tax liabilities. The AMT credit carryforward has no expiration date. Of the $171 million tax benefit for operating loss carryforwards, all of which relates to foreign jurisdictions, $106 million has no expiration date and $65 million will expire in 2010.

8. Commodity Hedging Contracts and Other Derivatives

The Company uses derivative instruments to manage risks associated with natural gas and crude oil price volatility as well as interest rate fluctuations. Derivative instruments that meet the hedge criteria in SFAS No. 133 are designated as cash-flow hedges or fair-value hedges. Derivative instruments that do not meet the hedge criteria in SFAS No. 133 are not designated as hedges. Derivative instruments designated as cash-flow hedges are used by the Company to mitigate the risk of variability in cash flows from natural gas and crude oil sales due to changes in market prices. Fair-value hedges are used by the Company to hedge or offset the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment.

Cash-Flow Hedges

At December 31, 2004, the Company's cash-flow hedges consisted of fixed-price swaps and producer collars (purchased put options and written call options). The fixed-price swap agreements are used to fix the prices of anticipated future natural gas production. The producer collars are used to establish floor and ceiling prices on anticipated future natural gas and crude oil production. There were no net premiums received when the Company entered into these option agreements.

Fair-Value Hedges

At December 31, 2004, the Company's fair-value hedges consisted of commodity price swaps and interest rate swaps. The Company's commodity price swaps are used to hedge against changes in the fair value of unrecognized firm commitments representing physical contracts that require the delivery of a specified quantity of natural gas or crude oil at a fixed price over a specified period of time. The swap agreements allow the Company to receive market prices for the committed specified quantities included in the physical contracts.

At December 31, 2004, the Company has interest rate swap agreements with an aggregate notional amount of $50 million related to principal amounts of $50 million, 5.6% Notes due December 1, 2006. The objective of these transactions is to protect the designated debt against changes in fair value due to changes in the benchmark interest rate, which was designated as six-month LIBOR. Under the interest rate swap agreements, the Company receives a fixed rate equal to 5.6% per annum and pays the benchmark interest rate plus 3.36 percent. Interest expense on the debt is adjusted to reflect payments made or received under the hedge agreements.

As of December 31, 2004, the Company had the following commodity related derivative instruments outstanding with average underlying prices that represent hedged prices of commodities at various market locations.

			Notional Amount			
Settlement Period	**Derivative Instrument**	**Hedge Strategy**	**Gas (MMBTU)**	**Oil (Barrels)**	**Average Underlying Prices**	**Fair Value Asset (Liability) (In Millions)**
2005	Swap	Cash flow	11,411,522		$ 4.06	$(16)
	Purchased put	Cash flow	95,472,358		5.82	56
	Written call	Cash flow	95,472,358		7.82	(16)
	Purchased put	Cash flow		3,795,000	41.81	16
	Written call	Cash flow		3,795,000	53.79	(5)
	Swap	Fair value	2,324,200		3.92	4
	N/A	Fair value (obligation)	2,324,200		3.92	(4)
	Swap	Not designated	5,350,000		(0.09)	—
2006	Swap	Cash flow	912,500		3.06	(2)
2007	Swap	Cash flow	760,000		$ 3.06	(2)
						$ 31

As of December 31, 2004, the Company had the following derivative instruments outstanding related to interest rate swaps.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount (In Millions)	Average Underlying Rate	Average Floating Rate	Fair Value Liability (In Millions)
2005	Interest rate swap	Fair value	$50	5.6%	LIBOR + 3.36%	$—
2006	Interest rate swap	Fair value	$50	5.6%	LIBOR + 3.36%	(1)
						$(1)

The derivative assets and liabilities represent the market values of the Company's derivative instruments as of December 31, 2004. During the years ended 2004, 2003 and 2002, hedging activities related to cash settlements decreased revenues $40 million, $63 million and increased revenues $114 million, respectively. In addition, during 2004, 2003 and 2002, gains of $2 million, and losses of $200 thousand and $22 million, respectively, were recorded in revenues associated with ineffectiveness of cash-flow and fair-value hedges. During 2004, 2003 and 2002, gains of $1 million, $9 million and losses of $10 million, respectively, were recorded in revenues related to changes in fair value of derivative instruments which do not qualify for hedge accounting.

Changes in other comprehensive income for the three years ended December 31, 2004 follow.

	(In Millions)
Accumulated other comprehensive income on hedging activities—December 31, 2001	$ 54
Reclassification adjustments for settled contracts	(68)
Current period changes in fair value of settled contracts	20
Changes in fair value of outstanding hedging positions	(38)
Accumulated other comprehensive loss on hedging activities—December 31, 2002	(32)
Reclassification adjustments for settled contracts	39
Current period changes in fair value of settled contracts	(18)
Changes in fair value of outstanding hedging positions	(10)
Accumulated other comprehensive loss on hedging activities—December 31, 2003	(21)
Reclassification adjustments for settled contracts	24
Current period changes in fair value of settled contracts	(8)
Changes in fair value of outstanding hedging positions	25
Accumulated other comprehensive income on hedging activities—December 31, 2004	$ 20

Based on commodity prices and foreign exchange rates as of December 31, 2004, the Company expects to reclassify gains of $33 million ($20 million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At December 31, 2004, the Company had derivative assets of $62 million and derivative liabilities of $32 million of which $62 million, $27 million and $5 million is included in Other Current Assets, Other Current Liabilities and Other Liabilities and Deferred Credits, respectively, on the Consolidated Balance Sheet.

9. Long-term Debt

Long-term debt follows.

December 31,	2004	2003
	(In Millions)	
Notes, 5.60%, due 2006	$ 500	$ 500
Notes, 6.60%, due 2007(1)	124	116
Notes, 5.70%, due 2007	350	350
Debentures, 9⅞%, due 2010	150	150
Notes, 6.50%, due 2011	500	500
Notes, 6.68%, due 2011	400	400
Notes, 6.40%, due 2011	178	178
Debentures, 7⅝%, due 2013	100	100
Debentures, 9⅛%, due 2021	150	150
Debentures, 7.65%, due 2023	88	88
Debentures, 8.20%, due 2025	150	150
Debentures, 6⅞%, due 2026	67	67
Debentures, 7⅜%, due 2029	92	92
Notes, 7.20%, due 2031	575	575
Notes, 7.40%, due 2031	500	500
Capital lease	6	—
Discounts and other	(41)	(43)
Total debt	3,889	3,873
Less current maturities	2	—
Total long-term debt	$3,887	$3,873

(1) Notes are denominated in Canadian dollars and reported in U.S. dollars.

The Company has debt maturities of $2 million due in 2005, $502 million due in 2006, $475 million due in 2007, $1 million due in 2008 and $2,950 million due in 2010 and thereafter. The fair value of debt outstanding as of December 31, 2004 and 2003 was $4,528 million and $4,483 million, respectively.

Burlington Resources Capital Trust I, Burlington Resources Capital Trust II (collectively, "the Trusts"), BR and Burlington Resources Finance Company ("BRFC") have a shelf registration of $1,500 million on file with the Securities and Exchange Commission ("SEC"). Pursuant to the registration statement, BR may issue debt securities, shares of common stock or preferred stock. In addition, BRFC may issue debt securities and the Trusts may issue trust preferred securities. Net proceeds, terms and pricing of offerings of securities issued under the shelf registration statement will be determined at the time of the offerings. BRFC and the Trusts are wholly owned finance subsidiaries of BR and have no independent assets or operations other than transferring funds to BR's subsidiaries. Any debt issued by BRFC is fully and unconditionally guaranteed by BR. Any trust preferred securities issued by the Trusts are also fully and unconditionally guaranteed by BR.

The Company has a $1.5 billion revolving credit facility ("Credit Facility") that includes (i) a US$500 million Canadian subfacility and (ii) a US$750 million sublimit for the issuance of letters of credit, including up to US$250 million in letters of credit under the Canadian subfacility. The Credit Facility expires in July 2009 unless extended. Under the covenants of the Credit Facility, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements). The Credit Facility is available to cover debt due within one year, therefore commercial paper, credit facility notes and fixed-rate debt due within one year are generally classified as long-term debt. At December 31, 2004, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

At the Company's option, interest on borrowings under the Credit Facility is based on the prime rate, Eurodollar rates or absolute rates. The Canadian subfacility bears interest at rates based on prime, Eurodollar or absolute rates also at the Company's option. The Company also has the option under the Canadian subfacility to request borrowings by way of bankers' acceptances.

The Company's access to funds from its Credit Facility is not restricted under any "material adverse condition" clauses. These clauses typically remove the obligation of the lenders to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations or properties considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material items of the credit agreement. While the Company's Credit Facility includes a covenant that requires the Company to report litigation or a proceeding that the Company has determined is likely to have a material adverse effect on the consolidated financial condition of the Company, the obligation of the lenders to fund the Credit Facility is not conditioned on the absence of such litigation or proceeding.

The Company has a closed deferred compensation plan funded by Company-owned life insurance policies that were entered into by LL&E prior to being acquired by BR. Outstanding borrowings of $160 million and $148 million as of December 31, 2004 and 2003, respectively, on these life insurance policies were reported as a reduction to the cash surrender value and are included as a component of Other Assets on the Company's Consolidated Balance Sheet.

10. Asset Retirement Obligations

On January 1, 2003, the Company adopted SFAS No. 143, *Asset Retirement Obligations*. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset is allocated to expense through depreciation or depletion of the asset. The majority of the Company's asset retirement obligations relate to plugging and abandoning oil and gas wells and related equipment as well as dismantling plants. During the first quarter of 2003, the Company recorded a net-of-tax cumulative effect of change in accounting principle charge of $59 million ($95 million before tax), increased long-term liabilities $191 million, net properties $96 million and deferred tax assets $36 million in accordance with the transition provisions of SFAS No. 143. There was no impact on the Company's cash flows as a result of adopting SFAS No. 143. The asset retirement obligations, which are included on the Company's Consolidated Balance Sheet in Other Liabilities and Deferred Credits, were $468 million and $442 million at December 31, 2004 and 2003, respectively. Accretion expense for 2004 was $27 million and is included in Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Income.

The following table reflects the changes in the Company's asset retirement obligations during the current year.

	(In Millions)
Carrying amount of asset retirement obligations as of December 31, 2003	$ 442
Liabilities incurred during the period	56
Liabilities settled during the period	(20)
Current year accretion expense	27
Revisions in estimated cash flows	(62)
Changes in foreign exchange rates during the period	25
Carrying amount of asset retirement obligations as of December 31, 2004	$ 468

The following table shows the pro forma effect on the Company's net income and earnings per share, had SFAS No. 143 been applied during the year ended December 31, 2002.

	(In Millions, Except per Share Amounts)
Net income—as reported	$ 454
Less: pro forma amounts assuming SFAS No. 143 was applied retroactively (unaudited)	9
Net income—pro forma (unaudited)	$ 445
Basic earnings per share—as reported	$1.13
Basic earnings per share—pro forma (unaudited)	1.11
Diluted earnings per share—as reported	1.13
Diluted earnings per share—pro forma (unaudited)	$1.10

11. Significant Concentrations

In 2004, 2003 and 2002, approximately 48 percent, 49 percent and 43 percent, respectively, of the Company's natural gas production was transported through pipeline systems owned by El Paso Natural Gas Company ("EPNG") and TransCanada Pipelines Limited ("TCPL"). Mechanical failure and regulatory action at certain points on the EPNG pipeline system could result in a substantial interruption of the transportation of the Company's natural gas production for a limited period of time in the San Juan Basin. TCPL, through its subsidiary, Nova Gas Transmission Ltd., gathers and transports a majority of the Company's Canadian gas production from multiple receipt points to multiple delivery points on their pipeline system. The interruption of gathering or transportation at any individual receipt point or delivery point would not have a material impact on the overall transportation of the Company's Canadian production. The Company takes steps to mitigate these risks through commercial insurance and identification of alternative pipeline transportation. The Company expects to continue to transport a substantial portion of its future natural gas production through these pipeline systems. See Note 14 of Notes to Consolidated Financial Statements for demand charges paid under firm and interruptible transportation capacity rights on pipeline systems.

During the year ended December 31, 2004, sales to BP and ConocoPhillips accounted for approximately 12 percent and 10 percent, respectively, of the Company's total revenues. Management believes that the loss of either of these customers would not have a material adverse effect on its results of operations or its financial position since the market for the Company's production is highly liquid with other willing buyers, including potential additional sales to existing customers, other than the two named above. During the years ended December 31, 2003 and 2002, no customer accounted for more than 10 percent of total revenues.

Substantially all of the Company's accounts receivable at December 31, 2004 and 2003 result from sales of natural gas, NGLs and crude oil as well as joint interest billings to third party companies also in the oil and gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. At December 31, 2004, 11 percent of the Company's accounts receivable balance was due from BP.

12. Capital Stock

On January 21, 2004, the Company's Board of Directors approved a 2-for-1 split on the Company's Common Stock in the form of a share distribution, subject to shareholder approval of an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares of the Company's Common Stock from 325 million to 650 million. On April 21, 2004, the Company's shareholders approved the amendment. As a result, the split was paid in the form of a share distribution on June 1, 2004 to shareholders of record on May 5, 2004. The effect on the December 31, 2003 balance sheet was to reduce Paid-in Capital by $2.4 million and increase Common Stock by $2.4 million. All prior period Common Stock and applicable share and per share amounts have been retroactively adjusted to reflect the split.

The Company's Common Stock activity follows.

	Number of Shares		
	Issued	**Treasury**	**Outstanding**
December 31, 2001	482,377,376	(80,791,390)	401,585,986
Shares issued under compensation plans, net of forfeitures		484,432	484,432
Option exercises		808,096	808,096
December 31, 2002	482,377,376	(79,498,862)	402,878,514
Treasury shares purchased		(14,829,980)	(14,829,980)
Shares issued under compensation plans, net of forfeitures		476,168	476,168
Option exercises		6,772,904	6,772,904
December 31, 2003	482,377,376	(87,079,770)	395,297,606
Treasury shares purchased		(14,358,000)	(14,358,000)
Treasury shares cancelled	(506)	506	—
Shares issued under compensation plans, net of forfeitures		418,731	418,731
Option exercises		6,583,132	6,583,132
December 31, 2004	482,376,870	(94,435,401)	387,941,469

Stock Compensation Plans

The Company's 2002 Stock Incentive Plan ("2002 Plan") succeeds its 1993 Stock Incentive Plan ("1993 Plan") which expired by its terms in April 2002 but remains in effect for options granted prior to April 2002. The 2002 Plan provides for the grant of stock options, restricted stock and stock appreciation rights (collectively, "2002 Awards").

Under the 2002 Plan, options may be granted to officers and key employees at fair market value on the date of grant, are exercisable in whole or part by the optionee after completion of at least one year of continuous employment from the grant date and have a term of ten years. The total number of shares of the Company's Common Stock for which 2002 Awards under the 2002 Plan may be granted is 15,000,000. At December 31, 2004, 10,323,845 shares were available for grant under the 2002 Plan.

In 1997, the Company adopted the 1997 Employee Stock Incentive Plan ("1997 Plan") from which stock options and restricted stock (collectively, "1997 Awards") may be granted to employees who are not eligible to participate in the plans adopted for officers and key employees. The options are granted at fair market value on the grant date, generally vest ratably over a period of three years from the date of the grant and have a term of ten years. The 1997 Plan was amended during 2002 to limit the maximum number of shares of the Company's Common Stock for which 1997 Awards under the 1997 Plan may be granted after April 2002 to 10,000,000 shares. At December 31, 2004, 8,087,224 shares were available for grant under the 1997 Plan, of which up to 300,000 shares annually may be restricted stock.

The Company issued 519,105, 578,850 and 514,050 shares of restricted stock in 2004, 2003 and 2002, respectively, from the 2002 and 1997 Plans. The restrictions on this stock generally lapse on the third anniversary of the date of grant. The weighted average grant-date fair value of restricted stock granted in the years ended December 31, 2004, 2003, and 2002 was approximately $29.44, $21.04 and $17.87, respectively. Related compensation expense of approximately $11 million, $11 million and $9 million was recognized for the years ended December 31, 2004, 2003 and 2002, respectively.

The Company's 2000 Stock Option Plan ("2000 Plan") for Non-Employee Directors provides for the annual grant of a nonqualified option for 4,000 shares of the Company's Common Stock immediately following the Annual Meeting of Stockholders to each Director who is not a salaried officer of the Company. In addition, an option for 10,000 shares is granted upon a Director's initial election or appointment to the Board of Directors. The options vest immediately and have a term of 10 years. The exercise price per share with respect to each option is the fair market value, as defined in the 2000 Plan, of the Company's Common Stock on the date the option is granted. The total number of shares of the Company's Common Stock for which options may be granted under the 2000 Plan is 500,000. At December 31, 2004, 262,000 shares were available for grant under the 2000 Plan.

The Company's stock option activity follows.

	Options	Weighted Average Exercise Price
December 31, 2001	13,728,516	$21.47
Granted	2,017,700	17.82
Exercised	(808,096)	15.90
Cancelled	(609,692)	22.56
December 31, 2002	14,328,428	21.22
Granted	3,955,780	21.06
Exercised	(6,772,904)	19.44
Cancelled	(562,224)	23.55
December 31, 2003	10,949,080	22.14
Granted	1,910,600	29.48
Exercised	(6,583,132)	22.74
Cancelled	(183,314)	24.00
December 31, 2004	6,093,234	$23.75

The following table summarizes information related to stock options outstanding and exercisable at December 31, 2004.

Options Outstanding	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price
266,772	$11.66–$17.42	$16.21	2.6	266,772	$16.21
3,976,862	17.69– 26.02	21.59	6.9	2,820,707	21.83
1,849,600	29.36– 40.65	29.48	9.1	68,000	31.92
6,093,234	$11.66–$40.65	$23.75	7.4	3,155,479	$21.57

Exercisable stock options and weighted average exercise prices at December 31, 2003 and 2002 follow.

	Options Exercisable	Weighted Average Exercise Price
December 31, 2003	6,797,856	$22.54
December 31, 2002	11,060,298	$21.61

Preferred Stock and Preferred Stock Purchase Rights

The Company is authorized to issue 75,000,000 shares of preferred stock, par value $.01 per share. On December 9, 1998, the Company's Board of Directors designated 3,250,000 of the authorized preferred shares as Series A Junior Participating Preferred Stock. Upon issuance, each two-hundredth of a share of Series A Junior Participating Preferred Stock will have dividend and voting rights approximately equal to those of one share of Common Stock of the Company. In addition, on December 9, 1998, the Board of Directors declared a dividend distribution of one Right for each outstanding share of Common Stock of the Company to shareholders of record on December 16, 1998. The Rights become exercisable if, without the Company's prior consent, a person or group acquires securities having 15 percent or more of the voting power of all of the Company's voting securities (an Acquiring Person) or ten days following the announcement of a tender offer which would result in such ownership. Each Right, when exercisable, entitles the registered holder to purchase from the Company two-hundredth of a share of Series A Junior Participating Preferred Stock at a price of $200 per two-hundredth of a share, subject to adjustment. If, after the Rights become exercisable, the Company were to be involved in a merger or other business combination in which its Common Stock was exchanged or changed or 50 percent or more of the Company's assets or earning power were sold, each Right would permit the holder to purchase, for the exercise price, stock of the acquiring company having a value of twice the exercise price. In addition, except for certain permitted offers, if any person or group becomes an Acquiring Person, each Right would permit the purchase, for the exercise price, of Common Stock of the Company having a value of twice the exercise price. Rights owned by an Acquiring Person are void. The Rights may be redeemed by the Company under certain circumstances until their expiration date for $.01 per Right.

13. Retirement Benefits

The Company's U.S. pension plans are non-contributory defined benefit plans covering all eligible U.S. employees. The benefits are based on years of credited service and final average compensation. Effective January 1, 2003, the Company amended its U.S. pension plan to provide cash balance benefits to new employees. U.S. employees hired before January 1, 2003, were given the choice to remain in the prior plan or accrue future benefits under the cash balance formula. Contributions to the tax qualified plans are limited to amounts that are currently deductible for tax purposes. Contributions are intended to provide not only for benefits attributed to service-to-date but also for those expected to be earned in the future. Hunter also provides a pension plan and postretirement benefits to a closed group of employees and retirees.

The Company provides postretirement medical, dental and life insurance benefits for a closed group of retirees and their dependents. The Company also provides limited retiree life insurance benefits to employees who retire under the pension plan. The postretirement benefit plans are unfunded, therefore, the Company funds claims on a cash basis.

The Company has discretionary defined contribution savings plans ("401(k) Plan" in the U.S.). Under the 401(k) Plan, an employee may elect to contribute from 1 to 13 percent of his/her eligible compensation subject to an Internal

Revenue Service limit of $13,000 in 2004. The Company matches with cash, up to 6 or 8 percent of the employee's eligible contributions based upon years of service. The Company contributed approximately $10 million, $9 million and $9 million to these plans for the years ended December 31, 2004, 2003 and 2002, respectively, to match eligible contributions by employees.

The Company provides a charitable award benefit to Directors who were elected to serve on the Board of Directors prior to February 2003 and served for at least two years. Upon the death of a Director who qualifies for this benefit, the Company will donate $1 million to one or more educational institutions of higher learning or other charitable organizations, which may include private foundations, nominated by the Director. At December 31, 2004, a $9 million liability has been accrued for these benefits and is included in Other Liabilities and Deferred Credits on the Company's Consolidated Balance Sheet.

The following tables set forth the pension and postretirement amounts recognized in the Consolidated Balance Sheet.

	Pension Benefits		Postretirement Benefits	
Year Ended December 31,	**2004**	**2003**	**2004**	**2003**
	(In Millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$222	$187	$ 46	$ 42
Service cost	11	9	—	—
Interest cost	13	13	2	3
Plan amendment	1	—	(3)	—
Actuarial loss	15	24	(6)	7
Currency exchange	2	4	—	—
Participant contributions	—	—	2	1
Benefits paid	(14)	(15)	(5)	(7)
Benefit obligation at end of year	250	222	36	46
Change in plan assets				
Fair value of plan assets at beginning of year	180	138	—	—
Actual return on plan assets	23	31	—	—
Currency exchange	2	4	—	—
Employer contribution	23	22	3	6
Participant contributions	—	—	2	1
Benefits paid	(14)	(15)	(5)	(7)
Fair value of plan assets at end of year	214	180	—	—
Funded status	(36)	(42)	(36)	(46)
Unrecognized net actuarial loss	51	51	17	23
Unrecognized prior service cost (benefit)	3	2	(8)	(5)
Net prepaid (accrued) benefit cost	$ 18	$ 11	$(27)	$(28)

The following table summarizes the projected benefit obligation, accumulated benefit obligation, fair value of plan assets and related consolidated balance sheet amounts for the Company's pension plans as of the measurement date.

	U.S.		Canada	
December 31,	**2004**	**2003**	**2004**	**2003**
	(In Millions)			
Benefit obligation	$225	$200	$ 25	$ 22
Accumulated benefit obligation	179	159	23	20
Fair value of plan assets	187	157	27	23
Accrued benefit liability	—	4	1	1
Prepaid benefit cost	$ 15	$ 12	$ 4	$ 4

The Company expects to contribute $12 million to its pension plans in 2005.

The following table summarizes pension and postretirement benefit expense for the three years ended December 31, 2004.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
	(In Millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 11	$ 9	$ 9	$ —	$ —	$ —
Interest cost	13	13	12	2	3	3
Expected return on plan assets	(13)	(13)	(14)	—	—	—
Recognized net actuarial loss	5	4	1	1	—	—
Net benefit cost	$ 16	$ 13	$ 8	$ 3	$ 3	$ 3

Assumptions used to determine net benefit obligations follow.

	Pension Benefits			Postretirement Benefits		
December 31,	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Weighted average assumptions						
Discount rate	5.75%	6.00%	6.75%	5.75%	6.00%	6.75%
Rate of compensation increase	4.50%	4.50%	4.50%	—	—	—

Assumptions used to determine net benefit cost follow.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Weighted average assumptions						
Discount rate	6.00%	6.75%	7.25%	6.00%	6.75%	7.25%
Expected return on plan assets	7.50	8.00	8.50	—	—	—
Rate of compensation increase	4.50%	4.50%	5.00%	—	—	—

The following table summarizes the future expected benefit payments to be paid from the pension and postretirement plans.

Year Ended	**Pension Payments**	**Postretirement Payments**
	(In Millions)	
2005	$ 16	$ 3
2006	18	3
2007	18	3
2008	20	3
2009	21	3
2010-2014	$140	$14

The following table provides the target and actual asset allocations for the Company's pension plans as of December 31.

	U.S.			Canada		
Asset Category	**Target**	**2004**	**2003**	**Target**	**2004**	**2003**
Equity	65%	67%	68%	58%	62%	60%
Fixed income	35	33	30	31	27	40
Other	—	—	2	11	11	—
Total	100%	100%	100%	100%	100%	100%

The primary investment objective is to ensure, over the long-term life of the pension plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries. In meeting this objective, the pension plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk while maintaining asset allocations within 5 percent of the target allocation shown above.

To develop the expected long-term rate of return on assets assumption, the Company considered the current level of expected returns on risk-free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. Since the Company's investment policy is to actively manage certain asset classes where the potential exists to outperform the broader market, the expected returns for those asset classes were adjusted to reflect the expected additional returns. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. This process resulted in the selection of the 7.5 percent assumption.

A 9 percent annual rate of increase in the per capita cost of pre-age 65 covered health care benefits was assumed for 2005. The rate is assumed to decrease gradually to 5 percent for 2009 and remain at that level thereafter. An 11 percent annual rate of increase in the per capita cost of post-age 65 covered health care benefits was assumed to gradually decrease to 5 percent for 2011 and remain at that level thereafter. Assumed health care cost trends have a significant effect on the amounts reported for the postretirement medical and dental care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Effect on total service and interest cost	$ 179	$ (156)
Effect on postretirement benefit obligation	$2,977	$(2,595)

14. Commitments and Contingent Liabilities

Transportation Demand Charges

The Company has entered into contracts which provide firm transportation capacity rights on pipeline systems. The remaining terms on these contracts range from 1 to 19 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. The Company paid $193 million, $179 million and $156 million of demand charges for the years ended December 31, 2004, 2003 and 2002, respectively. All transportation costs including demand charges are included in transportation expense in the Consolidated Statement of Income.

Future transportation demand charge commitments at December 31, 2004 follow.

	(In Millions)
2005	$165
2006	130
2007	107
2008	88
2009	74
Thereafter	382
Total	$946

Lease Obligations and Other Commitments

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $35 million, $38 million and $29 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2004 follow.

	(In Millions)
2005	$ 30
2006	28
2007	27
2008	29
2009	29
Thereafter	145
Total	$288

The Company has drilling rig commitments of $7 million and $4 million for 2005 and 2006, respectively.

Legal Proceedings

The Company and numerous other oil and gas companies have been named as defendants in various lawsuits alleging violations of the civil False Claims Act. These lawsuits were consolidated during 1999 and 2000 for pre-trial proceedings by the United States Judicial Panel on Multidistrict Litigation in the matter of *In re Natural Gas Royalties Qui Tam Litigation,* MDL-1293, United States District Court for the District of Wyoming ("MDL-1293"). The plaintiffs contend that defendants underpaid royalties on natural gas and NGLs produced on federal and Indian lands through the use of below-market prices, improper deductions, improper measurement techniques and transactions with affiliated companies during the period of 1985 to the present. Plaintiffs allege that the royalties paid by defendants were lower than the royalties required to be paid under federal regulations and that the forms filed by defendants with the Minerals Management Service ("MMS") reporting these royalty payments were false, thereby violating the civil False Claims Act. The United States has intervened in certain of the MDL-1293 cases as to some of the defendants, including the Company. The plaintiffs and the intervenor have not specified in their pleadings the amount of damages they seek from the Company. On December 5, 2003, the United States Judicial Panel on Multidistrict Litigation entered an order transferring the cases alleging claims of below-market prices, improper deductions, and transactions with affiliated companies for further pre-trial proceedings and trial in *Wright v. AGIP,* 5:03CV264, United States District Court for the Eastern District of Texas, Texarkana Division. All parties are proceeding with pre-trial discovery, and the trial of these cases is scheduled to begin in February 2007. The cases alleging improper measurement techniques remain pending in MDL-1293, and motions to dismiss have been filed by the Company and other defendants and are pending before the Court.

Various administrative proceedings are also pending before the MMS of the United States Department of the Interior with respect to the valuation of natural gas produced by the Company on federal and Indian lands. In general, these proceedings stem from regular MMS audits of the Company's royalty payments over various periods of time and involve the interpretation of the relevant federal regulations. Most of these proceedings involve production volumes and royalties that are the subject of Natural Gas Royalties Qui Tam Litigation.

Based on the Company's present understanding of the various governmental and civil False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. The Company is also exploring the possibility of a settlement of these claims. Although there has been no formal demand for damages, the Company currently estimates, based on its communications with the intervenor, that the amount of underpaid royalties on onshore production claimed by the intervenor in these proceedings is approximately $76 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could be subject to double damages, civil monetary penalties and other sanctions, including a temporary suspension from bidding on and entering into future federal mineral leases and other federal contracts for a defined period of time. As an alternative to monetary penalties under the False Claims Act, the intervenor has informed the Company that it may seek the recovery of interest payments of approximately $95 million. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter.

The Company has also been named as a defendant in the lawsuit styled *UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al,* No. 98-854, filed in 1995 in the District Court in The Hague and currently pending in the Court of Appeal in The Hague, the Netherlands. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.5 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a Judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeal in The Hague issued an interim Judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. After receiving additional evidence from the parties, the Court of Appeals subsequently issued a ruling in favor of defendants. In an interim Judgment issued on December 18, 2003, the Court of Appeals found that defendants should not have assumed that they were extracting oil from the Q-1 Block, that Unocal was not entitled to compensation for any production occurring prior to 1992 and that damages, if any, would be limited to the proceeds Unocal would have received for oil extracted from the Q-1 Block, less the costs Unocal would have incurred to produce the oil from an existing well in the L16a Block. The Court of Appeals ordered that further evidence be presented to a court appointed expert to determine whether any damages had been suffered by Unocal. The Company and the other defendants are continuing to present evidence to the Court and vigorously assert defenses against these claims. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. Based on the information known to date, the Company believes that Unocal suffered no damages in excess of the costs of production and that the Company will incur no liability in this matter other than the costs of litigation. The Company has not established a reserve for this matter since it currently does not believe that an unfavorable outcome is probable.

The Company and its former affiliate, El Paso Natural Gas Company, have also been named as defendants in two class action lawsuits styled *Bank of America, et al. v. El Paso Natural Gas Company, et al.*, Case No. CJ-97-68, and *Deane W. Moore, et al. v. Burlington Northern, Inc., et. al.*, Case No. CJ-97-132, each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. Plaintiffs contend that defendants underpaid royalties from 1982 to the present on natural gas produced from specified wells in Oklahoma through the use of below-market prices, improper deductions and transactions with affiliated companies and in other instances failed to pay or delayed in the payment of royalties on certain gas sold from these wells. The plaintiffs seek an accounting and damages for alleged royalty underpayments, plus interest from the time such amounts were allegedly due. Plaintiffs additionally seek the recovery of punitive damages. The plaintiffs have not specified in their pleadings the amount of damages they seek from the Company. However, through pre-trial discovery, plaintiffs have provided defendants with alternative theories of recovery claiming monetary damages of up to $221 million in principal, plus $996 million in interest, and unspecified punitive damages and attorney's fees. The Company believes it has substantial defenses to these claims and is vigorously asserting such defenses. The Company and El Paso Natural Gas Company have asserted contractual claims for indemnity against each other. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties are proceeding with pre-trial discovery. It is anticipated that the trial of this matter will be scheduled during 2005. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter.

The Company received notice on October 19, 2004 from the United States Department of Justice that it may be one of many potentially responsible parties under the Comprehensive Environmental Response, Compensation and Liability Act, as amended, with respect to the remediation of a site known as the Castex Systems, Inc. Oil Field Waste Disposal Site in Jefferson Davis Parish near Jennings, Louisiana. According to the Department of Justice, the remediation of the site has been completed under the supervision of the United States Environmental Protection Agency for a total cost of approximately $3 million. The Company has been informed that it may have contributed up to two and one-half percent (2.5 %) of the liquid oil field waste and twelve percent (12%) of the solid oil field waste identified at the site. The Company has signed an agreement tolling the statute of limitations for a period of approximately three months and is currently investigating this matter to determine if it is liable for any portion of the remediation costs.

In addition to the foregoing, the Company and its subsidiaries are named defendants in numerous other lawsuits and named parties in numerous governmental and other proceedings arising in the ordinary course of business, including: claims for personal injury and property damage, claims challenging oil and gas royalty, ad valorem and severance tax payments, claims related to joint interest billings under oil and gas operating agreements, claims alleging mismeasurement of volumes and wrongful analysis of heating content of natural gas and other claims in the nature of contract, regulatory or employment disputes. None of the governmental proceedings involve foreign governments.

While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these legal proceedings and environmental matters through settlement or adverse judgment will not have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

At December 31, 2004, the Company's Consolidated Balance Sheet included reserves for legal proceedings of $84 million and environmental matters of $15 million. The accrual of reserves for legal and environmental matters is included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional loss, the amount of which is not currently estimable, in excess of the amounts currently accrued with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings and environmental matters will exceed current accruals by an amount that would have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

15. Supplemental Cash Flow Information

The following is additional information concerning supplemental disclosures of cash payments.

Year Ended December 31,	2004	2003	2002
		(In Millions)	
Interest paid—net of capitalized interest(1)	$275	$251	$260
Income taxes paid—net	$274	$171	$ 40

(1) The Company had no capitalized interest in 2004. Capitalized interest was $25 million and $22 million for the years ended December 31, 2003 and 2002, respectively.

At December 31, 2004 and 2003, capital expenditures included in the Accounts Payable balance on the Company's Consolidated Balance Sheet were $333 million and $171 million, respectively. During the year ended December 31, 2004, the Company acquired $6 million of assets through a capital lease.

16. Impairment of Oil and Gas Properties

The Company performs an impairment analysis annually for unproved reserves or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon management's estimates of natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves.

In connection with the preparation of its financial statements, the Company recorded an impairment charge of $90 million for the year ended December 31, 2004 related to unproved properties in Canada. During the year ended December 31, 2003, the Company recorded charges of $63 million related to the impairment of oil and gas properties due to performance related downward reserve adjustments associated with certain properties primarily in Canada.

17. Segment and Geographic Information

The Company's reportable segments are U.S., Canada and International. The Company is engaged principally in the exploration, development, production and marketing of natural gas, crude oil and NGLs. The Company's reportable segments are managed separately based on their geographic location. The accounting policies for the segments are the same as those described in Note 1 of Notes to Consolidated Financial Statements. There were no intersegment sales in 2004 and 2003. Intersegment sales were $17 million in 2002.

The following tables present information about reported segment operations.

	North America			
Year Ended December 31, 2004	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Revenues	$2,710	$2,100	$ 808	$ 5,618
Depreciation, depletion and amortization	363	535	214	1,112
Impairment of oil and gas properties	—	90	—	90
Income before income taxes	1,612	891	341	2,844
Properties—net	3,984	5,541	1,417	10,942
Goodwill	—	1,054	—	1,054
Capital expenditures	$ 719	$ 842	$ 166	$ 1,727

	North America			
Year Ended December 31, 2003	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Revenues	$2,111	$1,925	$ 275	$ 4,311
Depreciation, depletion and amortization	307	493	102	902
Impairment of oil and gas properties	5	58	—	63
Income before income taxes and cumulative effect of change in accounting principle	1,124	869	39	2,032
Properties—net	3,608	5,102	1,505	10,215
Goodwill	—	982	—	982
Capital expenditures	$ 545	$ 715	$ 505	$ 1,765

	North America			
Year Ended December 31, 2002	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Revenues	$1,642	$1,165	$ 161	$ 2,968
Depreciation, depletion and amortization	350	382	78	810
Income (loss) before income taxes	817	278	(99)	996
Properties—net	3,433	4,008	961	8,402
Goodwill	—	803	—	803
Capital expenditures	$ 491	$ 876	$ 435	$ 1,802

The following is a reconciliation of segment income before income taxes and cumulative effect of change in accounting principle to consolidated income before income taxes and cumulative effect of change in accounting principle. For segment reporting purposes, corporate expenses, total interest expense and other expense (income)—net have been excluded from segment operations.

Year Ended December 31,	**2004**	**2003**	**2002**
		(In Millions)	
Income before income taxes and cumulative effect of change in accounting principle for reportable segments	$ 2,844	$ 2,032	$ 996
Corporate expenses	239	189	184
Interest expense	282	260	274
Other expense (income)—net	19	13	(31)
Consolidated income before income taxes and cumulative effect of change in accounting principle	$ 2,304	$ 1,570	$ 569

The following is a reconciliation of segment additions to properties to consolidated amounts.

Year Ended December 31,	**2004**	**2003**	**2002**
		(In Millions)	
Total capital expenditures for reportable segments	$ 1,727	$ 1,765	$1,802
Corporate administrative capital expenditures	20	23	35
Consolidated capital expenditures	$ 1,747	$ 1,788	$1,837

The following is a reconciliation of segment net properties to consolidated amounts.

December 31,	**2004**	**2003**	**2002**
		(In Millions)	
Properties—net for reportable segments	$10,942	$10,215	$8,402
Corporate properties—net	91	96	101
Consolidated properties—net	$11,033	$10,311	$8,503

18. Taxes Other Than Income Taxes

Taxes other than income taxes are as follow.

Year Ended December 31,	**2004**	**2003**	**2002**
		(In Millions)	
Severance taxes	$ 204	$ 141	$ 85
Ad valorem taxes	36	30	25
Payroll taxes and other	20	16	13
Taxes other than income taxes	$ 260	$ 187	$ 123

19. Other Matters

Recent Accounting Pronouncements

In January 2005, the Financial Accounting Standards Board ("FASB") issued SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29.* This statement, which addresses the measurement of exchanges of nonmonetary assets, is effective prospectively for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of this statement is not expected to impact the Company's consolidated financial position or results of operations.

In January 2005, the FASB issued SFAS No. 151, *Inventory Costs,* which is effective prospectively for inventory costs incurred during fiscal years beginning after June 15, 2005. SFAS No. 151 amends Accounting Research Bulletin No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs, and wasted materials should be recognized as current period charges. The adoption of this statement is not expected to impact the Company's consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (revised 2004) or SFAS No. 123(R), *Share-Based Payment*. This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company will adopt this statement on July 1, 2005 using the modified prospective application method described in the statement. Under the modified prospective application method, the Company will apply the standard to new awards and to awards modified, repurchased, or cancelled after the required effective date. Additionally, compensation cost for the unvested portion of awards outstanding as of the required effective date will be recognized as compensation expense as the requisite service is rendered after the required effective date. The adoption of this statement is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46, ("FIN 46"), *Consolidation of Variable Interest Entities*. FIN 46, as amended by FIN 46(R), provides guidance on how to identify a variable interest entity ("VIE"), and determine when the assets, liabilities, and results of operations of a VIE need to be included in a company's consolidated financial statements. FIN 46 also requires additional disclosures by primary beneficiaries and other significant variable interest holders in a VIE. The provisions of FIN 46 were effective immediately for all VIEs created after January 31, 2003. For VIEs created before February 1, 2003, the provisions of FIN 46, as amended, were effective on January 1, 2004. After evaluating this accounting pronouncement, the Company determined that it did not have any interests in any VIEs. Therefore, the adoption of FIN 46 did not have any impact on the Company's consolidated financial position, results of operations or cash flows.

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January 17, 2005

Burlington Resources Inc.
717 Texas Avenue, Suite 2100
Houston, TX 77002

Re: Proved Reserves as of December 31, 2004

Gentlemen:

At your request, we reviewed the estimates of domestic and international proved reserves of oil, condensate, natural gas, and natural gas liquids (NGLs) that Burlington Resources Inc. (BR) attributes to its net interests in oil and gas properties as of December 31, 2004. BR's estimates of proved reserves shown below are in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a).

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, Condensate, and NGLs, Million Barrels	427.3	130.9	558.2
Gas, Billions of Cubic Feet	4,180.8	1,715.5	5,896.3

Based on our investigations and subject to the limitations described hereinafter, it is our judgment that (1) BR has an effective system for gathering data and documenting information required to estimate its proved reserves; (2) in making its estimates, BR uses appropriate engineering, geologic, and evaluation principles and techniques that are in accordance with practices generally accepted in the petroleum industry; and (3) the results of the estimates prepared by BR that we reviewed are, in the aggregate, reasonable.

Gas volumes were estimated at the appropriate pressure base and temperature base established for each well or field by the applicable sales contract or regulatory body. Total gas reserves were obtained by summing the reserves for all the individual properties and are therefore stated at a mixed pressure base.

In conducting our audit, we reviewed BR's estimates of wet gas volumes prior to adjustment for impurities, shrinkage, and NGL recovery. We reviewed these wet gas volumes, along with the methods employed by BR, to convert these volumes to sales gas volumes and NGLs. In our judgment, the conversion methods used by BR to adjust the wet volumes to account for impurities, fuel use, shrinkage, and NGL recovery are appropriate and reasonable.

We reviewed approximately 84 percent of BR's estimated proved reserves forecasts and either accepted their forecast or revised it as needed. We selected the sampling of properties for independent estimates and review. In general, those properties with the largest reserves were selected for review. We investigated the pertinent available engineering, geological, and accounting information to satisfy ourselves that BR's reserve estimates are, in the aggregate, reasonable. In making our reserve estimates and comparing them with BR's estimates, we used product prices and expenses provided by BR. The prices used were represented by BR as the actual prices received for oil, condensate, natural gas, and NGLs on December 31, 2004, and are in accordance with Securities and Exchange Commission guidelines.

Burlington Resources Inc.

January 17, 2005
Page 2

These reserve estimates are based primarily on decline curve analysis, material balance calculations, volumetric calculations, analogies, or combinations of these methods. Reserve estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves were produced.

In conducting these evaluations, we relied upon production histories, accounting data, and other financial, operating, engineering, geological and geophysical data supplied by BR. To a lesser extent, data existing in the files of Miller and Lents, Ltd. and data obtained from commercial services were used. We also relied, without independent verification, upon BR's representation of its ownership interests for each property.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in Burlington Resources Inc. or any affiliated company. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity. Production of this report was supervised by an officer of the firm who is a professionally qualified and licensed Professional Engineer in the State of Texas with more than 20 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those employed in this study may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those reviewed for this report.

Very truly yours,

MILLER AND LENTS, LTD.

By Christopher A. Butta
Senior Vice President

CAB / psh

Ref.: 1408.15168

January 11, 2005

Burlington Resources Inc.
Ste. 2100, 717 Texas Avenue
Houston, TX 77002-2712

Re: Unqualified Audit Opinion of Burlington Resources Incorporated Canadian Proved Reserves, as of December 31, 2004

Gentlemen:

At your request, we have examined the proved oil, natural gas liquids, and natural gas reserves estimates of Burlington Resources Incorporated ("Burlington") Canadian properties, as of December 31, 2004. Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

Table 1 presents Burlington's estimates of proved oil, natural gas liquids and natural gas reserves, which are in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a).

Table 1

Summary of Burlington Resources Incorporated Canadian Proved Reserves Estimates Using Net Marketable Gas Volumes

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, MMbbl	13.6	4.3	17.9
Natural Gas, Bcf	1,821	509	2,330
Natural Gas Liquids, MMbbl	44.7	9.4	54.1

The volumes of natural gas liquids are comprised of ethane, propane, butanes, condensate and pentanes plus. All volumes are reported net, after royalties.

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info@sproule.com, www.sproule.com

We are independent with respect to Burlington, as provided in the Standard Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our audit does not constitute a complete reserves study of the oil and gas properties of Burlington. In the conduct of our audit, we did not independently verify the accuracy and completeness of information and data furnished by Burlington with respect to ownership interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, etc. Burlington's Canadian reserves assignments were audited directly by a citrix link into the PEEP reserves database, and by reviewing available public data to determine if those assignments were reasonable. If in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

The proved developed producing reserves and production forecasts were estimated by production decline extrapolations, water-oil ratio trends, material balance, or by volumetric calculations. For some properties with insufficient performance history to establish trends, we estimated future production by analogy with other properties with similar characteristics. The past performance trends of many properties were influenced by production curtailments, workovers, waterfloods, and/or infill drilling. Actual future production may require that our estimated trends be significantly altered.

The estimated proved undeveloped reserves require significant capital expenditures for items such as the drilling, completion and tie-in of wells. The proved undeveloped reserves estimates for infill wells are based on analogies to similar infill wells in the same field and/or the production histories of offset wells in the same field.

Reserve estimates from volumetric calculations and from analogies are often less certain than reserves estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The reserves estimates presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgements based on accepted standards of professional investigation, but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical and engineering information. Government policies and market conditions different from those employed in this review may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those estimated in this audit.

In our opinion, the estimates of Burlington's proved reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

This letter is solely for the information of Burlington Resources Inc. and for the information and assistance of its independent public accountants in connection with their review of, and report upon, the financial statements of Burlington Resources Inc. This letter should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law.

Our working papers are available for review upon request. If you have any questions regarding the above, or if we may be of further assistance, please call us.

Sincerely,

By ______________________
Robert N. Johnson, P.Eng.
Manager, Engineering and Corporate Secretary

By ______________________
Kenneth H. Crowther, P.Eng
President

PERMIT TO PRACTICE
SPROULE ASSOCIATES LIMITED

Signature ______________________

Date Jan 11, 2005

PERMIT NUMBER: P 417
The Association of Professional Engineers,
Geologists and Geophysicists of Alberta

Supplemental Oil and Gas Disclosures—Unaudited

The supplemental data presented herein reflects information for all of the Company's oil and gas producing activities.

Costs incurred for oil and gas property acquisition, exploration and development activities follow.

Year Ended December 31, 2004	North America U.S.	North America Canada	International	Total
			(In Millions)	
Property acquisition				
Proved	$ 81	$ 4	$ —	$ 85
Unproved	32	33	2	67
Exploration	55	126	38	219
Development				
Proved developed	473	526	36	1,035
Proved undeveloped	71	113	54	238
Costs incurred before estimated asset retirement obligations	712	802	130	1,644
Estimated asset retirement obligations incurred(1)	18	(5)	(2)	11
Total costs incurred	$730	$797	$128	$1,655

Year Ended December 31, 2003	North America U.S.	North America Canada	International	Total
			(In Millions)	
Property acquisition				
Proved	$110	$ 19	$ 99	$ 228
Unproved	9	79	2	90
Exploration	43	135	33	211
Development				
Proved developed	246	375	36	657
Proved undeveloped	132	71	196	399
Costs incurred before estimated asset retirement obligations	540	679	366	1,585
Estimated asset retirement obligations incurred(1)	6	26	52	84
Total costs incurred	$546	$705	$418	$1,669

Year Ended December 31, 2002	North America U.S.	North America Canada	International	Total
			(In Millions)	
Property acquisition				
Proved	$178	$352	$ 74	$ 604
Unproved	4	13	—	17
Exploration	35	126	40	201
Development				
Proved developed	165	279	32	476
Proved undeveloped	81	69	153	303
Total costs incurred	$463	$839	$299	$1,601

(1) Amounts are shown net of current year estimated cash flow revisions.

The Company estimates that it will spend capital of approximately $503 million, $635 million and $405 million in 2005, 2006 and 2007, respectively, for the development of its proved undeveloped reserves.

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Results of operations for natural gas, NGLs and crude oil producing activities, which exclude processing and other activities, corporate general and administrative expenses and straight-line depreciation expense, were as follow. There were no intersegment sales in 2004 and 2003. Intersegment sales were $17 million in 2002.

	North America			
Year Ended December 31, 2004	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,690	$2,087	$807	$5,584
Production costs	407	200	97	704
Exploration costs	37	154	67	258
Operating expenses	284	221	90	595
Depreciation, depletion and amortization	346	512	212	1,070
Impairment of oil and gas properties	—	90	—	90
Income tax provision	554	315	201	1,070
Results of operations for oil and gas producing activities	$1,062	$ 595	$140	$1,797

	North America			
Year Ended December 31, 2003	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,089	$1,911	$275	$4,275
Production costs	317	173	46	536
Exploration costs	100	121	31	252
Operating expenses	270	206	58	534
Depreciation, depletion and amortization	288	461	100	849
Impairment of oil and gas properties	5	58	—	63
Income tax provision	345	201	10	556
Results of operations for oil and gas producing activities	$ 764	$ 691	$ 30	$1,485

	North America			
Year Ended December 31, 2002	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$1,631	$1,166	$161	$2,958
Production costs	307	141	23	471
Exploration costs	116	121	49	286
Operating expenses	233	191	43	467
Depreciation, depletion and amortization	330	358	75	763
Income tax provision	224	151	10	385
Results of operations for oil and gas producing activities	$ 421	$ 204	$(39)	$ 586

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

The following table reflects estimated quantities of proved natural gas, NGLs and crude oil reserves. These reserves have been estimated by the Company's petroleum engineers in accordance with the Securities and Exchange Commission's Regulations. The Company considers such estimates to be reasonable, however, due to inherent uncertainties, estimates of underground reserves are imprecise and subject to change over time as additional information becomes available.

Miller and Lents, Ltd. and Sproule Associates Limited, independent oil and gas consultants, have reviewed the estimates of proved reserves of natural gas, NGLs and crude oil that BR attributed to its net interests in oil and gas properties as of December 31, 2004. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and International interests and Sproule Associates Limited reviewed the Company's interests in Canada. Based on their review of more than 80 percent of the Company's reserve estimates, it is their judgment that the estimates are reasonable in the aggregate.

	Crude Oil (MMBbls)			
	North America			
	U.S.	Canada	International	Worldwide
Proved Developed and Undeveloped Reserves				
December 31, 2001	244.3	56.6	71.0	371.9
Revisions of previous estimates	(2.0)	(1.4)	(1.6)	(5.0)
Extensions, discoveries and other additions	2.8	5.3	6.3	14.4
Production	(13.0)	(2.8)	(2.1)	(17.9)
Purchase of reserves in place	1.2	—	19.9	21.1
Sales of reserves in place	(46.1)	(43.3)	(7.2)	(96.6)
December 31, 2002	187.2	14.4	86.3	287.9
Revisions of previous estimates	(4.9)	0.4	1.7	(2.8)
Extensions, discoveries and other additions	11.0	2.8	—	13.8
Production	(10.7)	(1.9)	(4.4)	(17.0)
Purchase of reserves in place	0.5	0.1	—	0.6
Sales of reserves in place	(0.3)	(0.1)	—	(0.4)
December 31, 2003	182.8	15.7	83.6	282.1
Revisions of previous estimates	13.7	(0.7)	6.0	19.0
Extensions, discoveries and other additions	18.9	4.9	1.2	25.0
Production	(13.7)	(2.0)	(15.5)	(31.2)
Purchase of reserves in place	2.8	—	—	2.8
Sales of reserves in place	—	—	—	—
December 31, 2004	204.5	17.9	75.3	297.7
Proved Developed Reserves				
December 31, 2001	163.7	38.4	8.8	210.9
December 31, 2002	155.2	12.9	12.9	181.0
December 31, 2003	176.5	13.1	50.8	240.4
December 31, 2004	185.8	13.6	48.5	247.9

NGLs (MMBbls)			Natural Gas (BCF)				
North America			North America				Total Equivalent
U.S.	Canada	Worldwide	U.S.	Canada	International	Worldwide	(BCFE)
227.7	47.7	275.4	4,892	2,136	897	7,925	11,808
9.8	14.7	24.5	(14)	(140)	(11)	(165)	(48)
15.7	9.2	24.9	350	341	85	776	1,012
(11.9)	(10.0)	(21.9)	(346)	(293)	(60)	(699)	(938)
—	0.2	0.2	153	268	—	421	549
(0.9)	(2.0)	(2.9)	(282)	(16)	(70)	(368)	(965)
240.4	59.8	300.2	4,753	2,296	841	7,890	11,418
19.8	(0.7)	19.1	(88)	(57)	(45)	(190)	(91)
22.9	12.0	34.9	425	427	54	906	1,198
(13.6)	(10.0)	(23.6)	(315)	(317)	(61)	(693)	(937)
0.6	0.3	0.9	131	9	79	219	228
(0.5)	(0.1)	(0.6)	(54)	(4)	—	(58)	(64)
269.6	61.3	330.9	4,852	2,354	868	8,074	11,752
4.0	(8.5)	(4.5)	40	(77)	2	(35)	52
19.7	9.8	29.5	475	352	18	845	1,172
(15.3)	(8.6)	(23.9)	(333)	(300)	(68)	(701)	(1,031)
0.5	0.1	0.6	43	4	—	47	67
(0.1)	—	(0.1)	(1)	(3)	—	(4)	(5)
278.4	54.1	332.5	5,076	2,330	820	8,226	12,007
175.5	39.3	214.8	3,771	1,758	384	5,913	8,467
179.2	53.1	232.3	3,617	1,836	263	5,716	8,196
188.6	50.8	239.4	3,715	1,837	322	5,874	8,753
193.1	44.6	237.7	3,745	1,821	435	6,001	8,915

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

A summary of the standardized measure of discounted future net cash flows relating to proved natural gas, NGLs and crude oil reserves is shown below. Future net cash flows are computed using year end commodity prices, costs and statutory tax rates (adjusted for tax credits and other items) that relate to the Company's existing proved natural gas, NGLs and crude oil reserves.

	North America			
2004	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Future cash inflows	$38,750	$14,787	$5,544	$59,081
Less related future				
Production costs	8,070	2,705	1,063	11,838
Development costs	1,658	1,047	429	3,134
Income taxes	9,927	3,208	1,445	14,580
Future net cash flows	19,095	7,827	2,607	29,529
10% annual discount for estimated timing of cash flows	10,575	2,948	788	14,311
Standardized measure of discounted future net cash flows	$ 8,520	$ 4,879	$1,819	$15,218

	North America			
2003	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Future cash inflows	$34,868	$14,689	$5,357	$54,914
Less related future				
Production costs	6,551	2,219	1,342	10,112
Development costs	888	717	424	2,029
Income taxes	9,351	3,416	1,102	13,869
Future net cash flows	18,078	8,337	2,489	28,904
10% annual discount for estimated timing of cash flows	9,937	3,028	762	13,727
Standardized measure of discounted future net cash flows	$ 8,141	$ 5,309	$1,727	$15,177

	North America			
2002	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Future cash inflows	$24,879	$10,563	$3,861	$39,303
Less related future				
Production costs	5,543	1,634	1,072	8,249
Development costs	750	327	614	1,691
Income taxes	6,018	2,940	475	9,433
Future net cash flows	12,568	5,662	1,700	19,930
10% annual discount for estimated timing of cash flows	6,976	1,894	646	9,516
Standardized measure of discounted future net cash flows	$ 5,592	$ 3,768	$1,054	$10,414

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved natural gas, NGLs and crude oil reserves follows.

	2004	2003	2002
		(In Millions)	
January 1,	$15,177	$10,414	$ 6,000
Revisions of previous estimates			
Changes in prices and costs	606	6,050	6,744
Changes in quantities	173	(111)	(26)
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,978	2,119	1,235
Purchases of reserves in place	126	416	656
Sales of reserves in place	(10)	(86)	(1,215)
Accretion of discount	2,165	1,472	815
Sales, net of production costs	(4,880)	(3,739)	(2,483)
Net change in income taxes	(401)	(2,163)	(2,158)
Changes in rate of production and other	284	805	846
Net change	41	4,763	4,414
December 31,	$15,218	$15,177	$10,414

Quarterly Financial Data—Unaudited

	2004				2003			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In Millions, Except per Share Amounts)							
Revenues	$1,558	$1,419	$1,333	$1,308	$1,065	$1,059	$1,059	$1,128
Income before income taxes and cumulative effect of change in accounting principle(a)	588	629	540	547	299	396	376	499
Income before cumulative effect of change in accounting principle(d)	400	394	379	354	387	267	278	328
Net income(b)	400	394	379	354	387	267	278	269
Basic earnings per common share before cumulative effect of change in accounting principle(c)	1.03	1.00	0.96	0.90	0.98	0.67	0.70	0.82
Net income(c)	1.03	1.00	0.96	0.90	0.98	0.67	0.70	0.67
Diluted earnings per common share before cumulative effect of change in accounting principle(c)(d)	1.02	1.00	0.96	0.89	0.98	0.67	0.69	0.81
Net income(b)(c)	1.02	1.00	0.96	0.89	0.98	0.67	0.69	0.67
Cash dividends declared per common share(c)	0.08	0.09	0.07	0.08	0.08	0.07	0.07	0.07
Common stock price range(c)								
High	46.41	41.24	37.49	31.98	28.73	27.04	27.98	24.04
Low	$39.19	$34.92	$31.23	$26.33	$23.48	$22.52	$22.92	$20.38

(a) During the fourth quarter of 2004 and the second and fourth quarters of 2003, the Company recognized non-cash, pretax charges of $90 million, $30 million and $33 million, respectively, related to the impairment of oil and gas properties.

(b) Fourth quarter 2004 includes a tax benefit of $28 million ($0.07 per diluted share) related to the Canadian federal income tax reduction as well as a U.S. expense of $26 million ($0.07 per diluted share) related to the planned repatriation of $500 million under the one-time provisions of the American Jobs Creation Act of 2004. Fourth quarter 2003 includes a tax benefit of $203 million or $0.51 per diluted share related to the Canadian federal income tax reduction.

(c) Share amounts and per share amounts for periods prior to June 30, 2004 have been retroactively adjusted to reflect the stock split of the Company's Common Stock effective June 1, 2004.

(d) During the first quarter of 2003, the Company recorded a pre-tax charge of $95 million ($59 million after tax or $0.15 per diluted share) resulting from the adoption of SFAS No. 143.

ITEM NINE

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM NINE A

CONTROLS AND PROCEDURES

Under the supervision and with the participation of certain members of the Company's management, including the Chief Executive Officer and Chief Financial Officer, the Company completed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) to the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer believe that the disclosure controls and procedures were effective as of the end of the period covered by this report with respect to timely communicating to them and other members of management responsible for preparing periodic reports all material information required to be disclosed in this report as it relates to the Company and its consolidated subsidiaries.

The Company's management does not expect that its disclosure controls and procedures or its internal control over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some person or by collusion of two or more people. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Accordingly, the Company's disclosure controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our disclosure control system are met and, as set forth above, the Company's management has concluded, based on their evaluation as of the end of the period, that our disclosure controls and procedures were sufficiently effective to provide reasonable assurance that the objectives of our disclosure control system were met.

There was no change in the Company's internal control over financial reporting during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. See page 38 for Management Report on Internal Control over Financial Reporting.

ITEM NINE B

OTHER INFORMATION

None

PART III

ITEMS TEN AND ELEVEN

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT AND EXECUTIVE COMPENSATION

A definitive proxy statement for the 2004 Annual Meeting of Stockholders (the Proxy Statement) of the Company will be filed no later than 120 days after the end of the fiscal year with the Securities and Exchange Commission. The information set forth therein under "Election of Directors," "Executive Compensation" and "Section 16(a) Beneficial Ownership Reporting Compliance" is incorporated herein by reference. Certain information with respect to the executive officers of the Company is set forth under the caption "Executive Officers of the Registrant" in Part I of this report. Certain information with respect to the Audit Committee and Audit Committee financial experts is set forth under the caption "Corporate Governance" in the Proxy Statement and is incorporated herein by reference.

The Company has adopted a Code of Business Conduct and Ethics (Code of Conduct) that applies to directors, officers and employees, including the principal executive officer, principal financial officer and principal accounting officer or controller and has posted such code on its Web site at www.br-inc.com. Changes to and waivers granted with respect to the Company's Code of Conduct related to the above named officers, other executive officers and Directors required to be disclosed pursuant to the applicable rules and regulations will also be posted on the Company's Web site. The Company's Code of Conduct, as well as its Corporate Governance Guidelines and its Audit, Compensation and Governance and Nominating Committee charters are available on its Web site and in print to any shareholder who requests them.

ITEM TWELVE

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Certain information required by this item is set forth under the caption "Stock Ownership of Management and Certain Other Holders" in the Proxy Statement and is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

At December 31, 2004

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights(2) (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights(2) (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))(2) (c)
Equity compensation plans approved by security holders	4,506,902	$24.55	10,585,845
Equity compensation plan not approved by security holders(1)	1,586,332	21.49	8,087,224
Total	6,093,234	$23.75	18,673,069

(1) See Note 12 of Notes to Consolidated Financial Statements for a description of the Company's 1997 Employee Stock Incentive Plan, which is the only compensation plan in effect that was adopted without the approval of the Company's stockholders.

(2) The number of equity securities have been adjusted for the Company's 2-for-1 stock split paid in the form of a share distribution on June 1, 2004.

ITEM THIRTEEN

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item is set forth under the caption "Certain Relationships and Related Transactions" in the Proxy Statement and is incorporated herein by reference.

ITEM FOURTEEN

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is set forth under the caption "Independent Auditor Fees and Services" in the Proxy Statement and is incorporated herein by reference.

PART IV

ITEM FIFTEEN

EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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SIGNATURES REQUIRED FOR FORM 10-K

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Burlington Resources Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BURLINGTON RESOURCES INC.

By /s/ BOBBY S. SHACKOULS
Bobby S. Shackouls
Chairman of the Board, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Burlington Resources Inc. and in the capacities and on the dates indicated.

By: /s/ BOBBY S. SHACKOULS Bobby S. Shackouls	Chairman of the Board, President and Chief Executive Officer	February 28, 2005
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Director, Executive Vice President and Chief Financial Officer	February 28, 2005
/s/ JOSEPH P. McCOY Joseph P. McCoy	Vice President, Controller and Chief Accounting Officer	February 28, 2005
/s/ BARBARA T. ALEXANDER Barbara T. Alexander	Director	February 28, 2005
/s/ REUBEN V. ANDERSON Reuben V. Anderson	Director	February 28, 2005
/s/ LAIRD I. GRANT Laird I. Grant	Director	February 28, 2005
/s/ ROBERT J. HARDING Robert J. Harding	Director	February 28, 2005
/s/ JOHN T. LAMACCHIA John T. LaMacchia	Director	February 28, 2005
/s/ RANDY L. LIMBACHER Randy L. Limbacher	Director	February 28, 2005
/s/ JAMES F. McDONALD James F. McDonald	Director	February 28, 2005
/s/ KENNETH W. ORCE Kenneth W. Orce	Director	February 28, 2005
/s/ DONALD M. ROBERTS Donald M. Roberts	Director	February 28, 2005
/s/ JAMES A. RUNDE James A. Runde	Director	February 28, 2005
/s/ JOHN F. SCHWARZ John F. Schwarz	Director	February 28, 2005
/s/ WALTER SCOTT, JR. Walter Scott, Jr.	Director	February 28, 2005
/s/ WILLIAM E. WADE, JR. William E. Wade, Jr.	Director	February 28, 2005

AMENDED EXHIBIT INDEX

The following exhibits are filed as part of this report.

Exhibit Number	Description	
3.1	Certificate of Incorporation of Burlington Resources Inc. as amended April 21,2004 (Exhibit 3.1 to Form 10-Q, filed May 7, 2004)	*
3.2	By-Laws of Burlington Resources Inc. amended as of March 1, 2003 (Exhibit 3.2 to Form 10-K, filed March 12, 2003)	*
4.1	Form of Shareholder Rights Agreement dated as of December 16, 1998, between Burlington Resources Inc. and EquiServe Trust Company, N.A. (the current Rights Agent) which includes, as Exhibit A thereto, the form of Certificate of Designation specifying terms of the Series A Junior Participating Preferred Stock and, as Exhibit B thereto, the form of Rights Certificate (Exhibit 1 to Form 8-A, filed December 1998)	*
4.2	Indenture, dated as of June 15, 1990, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.2 to Form 8, filed February 1992)	*
4.3	Indenture, dated as of October 1, 1991, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.3 to Form 8, filed February 1992)	*
4.4	Indenture, dated as of April 1, 1992, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.4 to Form 8, filed March 1993)	*
4.5	Indenture, dated as of June 15, 1992, between The Louisiana Land and Exploration Company ('LL&E'') and Texas Commerce Bank National Association (as Trustee) (Exhibit 4.1 to LL&E's Form S-3, as amended, filed November 1993)	*
4.6	Indenture, dated as of February 12, 2001, between Burlington Resources Finance Company and Citibank, N.A. (as Trustee), including form of Debt Securities (Exhibit 4.2 to Form S-4, filed April 2002)	*
4.7	Guarantee Agreement, dated as of February 12, 2001, of Burlington Resources Inc. with Respect to Senior Debt Securities of Burlington Resources Finance Company (Exhibit 4.5 to Form S-4, filed April 2002)	*
4.8	The Company and its subsidiaries either have filed with the Securities and Exchange Commission or upon request will furnish a copy of any instruments with respect to long-term debt of the Company	*
†10.1	Burlington Resources Inc. Incentive Compensation Plan as amended and restated (Exhibit 10.29 to Form 10-Q, filed November 2000)	*
	Amendment to Burlington Resources Inc. Incentive Compensation Plan dated December 2000 (Exhibit 10.2 to Form 10-K, filed February 2001)	*
	Amendment No. 1, dated January 9, 2002, to Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.1 to Form 10-Q, filed April 2002)	*
	Amendment No. 2, dated July 21, 2004, to Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.4 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Incentive Compensation Plan	
†10.2	Burlington Resources Inc. Senior Executive Survivor Benefit Plan dated as of January 1, 1989 (Exhibit 10.11 to Form 8, filed February 1989)	*
†10.3	Burlington Resources Inc. Deferred Compensation Plan as amended and restated (Exhibit 10.4 to Form 10-K, filed February 1997)	*
	Amendment No. 1, dated July 21, 2004, to Burlington Resources Inc. Deferred Compensation Plan (Exhibit 10.3 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Deferred Compensation Plan (Filed as Exhibit 10.1 hereto)	

Exhibit Number	Description	
†10.4	Burlington Resources Inc. Supplemental Benefits Plan as amended and restated (Exhibit 10.5 to Form 10-K, filed February 1997)	*
	Amendment No. 4, dated January 1, 1997, to Burlington Resources Inc. Supplemental Benefits Plan (Exhibit 10.5 to Form 10-Q filed August 3, 2004)	*
	Amendment No. 5, dated July 21, 2004, to Burlington Resources Inc. Supplemental Benefits Plan (Exhibit 10.6 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Supplemental Benefits Plan (Filed as Exhibit 10.1 hereto)	
†10.5	Amended and Restated Employment Contract between the Company and Bobby S. Shackouls (Exhibit 10.29 to Form 10-Q, filed August 1999)	*
†10.6	Burlington Resources Inc. Compensation Plan for Non-Employee Directors as amended and restated (Exhibit 10.8 to Form 10-K, filed February 1997)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Compensation Plan for Non-Employee Directors (Filed as Exhibit 10.1 hereto)	
†10.7	Amended and Restated Burlington Resources Inc. Executive Change in Control Severance Plan (Exhibit 10.8 to Form 10-K, filed February 2001)	*
†10.8	Burlington Resources Inc. Retirement Income Plan for Directors (Exhibit 10.21 to Form 8, filed February 1991)	*
†10.9	Burlington Resources Inc. 1991 Director Charitable Award Plan, dated as of January 16, 1991 (Exhibit 10.21 to Form 8, filed February 1991)	*
	Amendment No. 1 dated April 9, 1997 to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.10 to Form 10-K, filed March 12, 2003)	*
	Amendment No. 2 dated January 22, 2003 to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.10 to Form 10-K, filed March 12, 2003)	*
	Amendment No. 3 dated December 2003 to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.9 to Form 10-K, filed February 26, 2004)	*
10.10	Master Separation Agreement and documents related thereto dated January 15, 1992 by and among Burlington Resources Inc., El Paso Natural Gas Company and Meridian Oil Holding Inc., including exhibits (Exhibit 10.24 to Form 8, filed February 1992)	*
†10.11	Burlington Resources Inc. 1992 Stock Option Plan for Non-employee Directors (Exhibit 28.1 of Form S-8, No. 33-46518, filed March 1992)	*
†10.12	Burlington Resources Inc. Key Executive Retention Plan and Amendments No. 1 and 2 (Exhibit 10.20 to Form 8, filed March 1993)	*
	Amendments No. 3 and 4 to the Burlington Resources Inc. Key Executive Retention Plan (Exhibit 10.17 to Form 10-K, filed February 1994)	*
†10.13	Burlington Resources Inc. 1992 Performance Share Unit Plan as amended and restated (Exhibit 10.17 to Form 10-K, filed February 1997)	*
†10.14	Burlington Resources Inc. 1993 Stock Incentive Plan (Exhibit 10.22 to Form 10-K, filed February 1994)	*
	Amendment to Burlington Resources Inc. 1993 Stock Incentive Plan dated April 2000 (Exhibit 10.15 to Form 10-K, filed February 2001)	*
	Amendment to Burlington Resources 1993 Stock Incentive Plan dated December 2000 (Exhibit 10.2 to Form 10-K, filed February 2001)	*
	Amendment to Burlington Resources Inc. 1993 Stock Incentive Plan dated December 2003 (Exhibit 10.14 to Form 10-K, filed February 26, 2004)	*
†10.15	Burlington Resources Inc. 1994 Restricted Stock Exchange Plan (Exhibit 10.23 to Form 10-K, filed February 1995)	*
	Amendment to Burlington Resources Inc. 1994 Restricted Stock Exchange Plan dated December 2000 (Exhibit 10.16 to Form 10-K, filed February 2001)	*
†10.16	Burlington Resources Inc. 1997 Performance Share Unit Plan (Exhibit 10.21 to Form 10-K, filed February 1997)	*

Exhibit Number	Description	
10.17	$1.5 billion Credit Agreement, dated July 29, 2004, between Burlington Resources Inc., Burlington Resources Canada Ltd. and Burlington Resources Canada (Hunter) Ltd., as Borrowers, and JPMorgan Chase Bank, as administrative agent (Exhibit 10.1 to Form 10-Q filed August 3, 2004)	*
†10.18	Form of The Louisiana Land and Exploration Company Deferred Compensation Arrangement for Selected Key Employees (Exhibit 10(g) to LL&E's Form 10-K, filed March 1991)	*
	Amendment to the LL&E Deferred Compensation Arrangement for Selected Key Employees dated December 21, 1998 (Exhibit 10.26 to Form 10-K, filed February 1999)	*
†10.19	The LL&E Supplemental Excess Plan (Exhibit 10(j) to LL&E's Form 10-K, filed March 1993)	*
†10.20	Form of agreement on pension related benefits with certain former Seattle holding company office employees, including L. David Hanower (Exhibit 10.26 to Form 10-K, filed March 17, 2000)	*
†10.21	Poco Petroleums Ltd. Incentive Stock Option Plan (Form S-8 No. 333-91247, filed November 18, 1999)	*
†10.22	Employee Savings Plan for Eligible Employees of Poco Petroleums Ltd. (Exhibit 4.4 to Form S-8 No. 333-95071, filed January 20, 2000)	*
†10.23	Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (Exhibit 10.12 to Form 10-K, filed February 1996)	*
	First Amendment to the Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (Exhibit 10.29 to Form 10-Q, filed May 2000)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (filed as Exhibit 10.1 hereto)	
†10.24	Burlington Resources Inc. 2000 Stock Option Plan for Non-Employee Directors (Exhibit 10.30 to Form 10-Q, filed August 2000)	*
†10.25	Letter agreement regarding Steven J. Shapiro dated October 18, 2000 related to supplemental pension benefits in connection with employment (Exhibit 10.29 to Form 10-K, filed February 2001)	*
†10.26	Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.30 to Form 10-K, filed February 2001)	*
	Amendment No. 1, dated January 9, 2002, to Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.2 to Form 10-Q, filed April 2002)	*
	Amendment No. 2, dated July 21, 2004, to Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.2 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. 2001 Performance Share Unit Plan (filed as Exhibit 10.1 hereto)	
†10.27	Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit A to Schedule 14A, filed March 15, 2002)	*
	Amendment No. 1 dated December 2003 to Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.29 to Form 10-K filed February 26, 2004)	*
	Amendment No. 2 dated December 2003 to Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.29 to Form 10-K filed February 26, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. 2002 Stock Incentive Plan (filed as Exhibit 10.1 hereto)	
10.28	Burlington Resources Inc. 1997 Employee Stock Incentive Plan Amendment dated December 2003 to Burlington Resources Inc. 1997 Employee Stock Incentive Plan (Exhibit 10.30 to Form 10-K, filed February 26, 2004)	*
10.29	Form of stock option grant letter under the Burlington Resources Inc. 2002 Stock Incentive Plan	
10.30	Form of restricted stock grant letter under the Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.8 to Form 10-Q filed August 3, 2004)	*
10.31	Burlington Resources Inc. 2005 Performance Share Unit Plan (Exhibit 10.2 to Form 8-K filed January 31, 2005)	*

Exhibit Number	Description	
10.32	Form of performance share unit grant letter under the Burlington Resources Inc. 2005 Performance Share Unit Plan (Exhibit 10.3 to Form 8-K filed January 31, 2005)	*
10.33	Summary of Performance Measures for the Burlington Resources Inc. Incentive Compensation Plan	
10.34	Summary of the Compensation of Non-Employee Directors of Burlington Resources Inc.	
21.1	Subsidiaries of the Registrant	
23.1	Consent of Independent Auditors — PricewaterhouseCoopers LLP	
23.2	Consent of Independent Oil and Gas Consultant — Miller and Lents, Ltd.	
23.3	Consent of Independent Oil and Gas Consultant — Sproule Associates Limited	
31.1	Rule 13a-14(a)/15d-14(a) Certification executed by Bobby S. Shackouls, Chairman of the Board, President and Chief Executive Officer of the Company	
31.2	Rule 13a-14(a)/15d-14(a) Certification executed by Steven J. Shapiro, Executive Vice President and Chief Financial Officer of the Company	
32.1	Section 1350 Certification	
32.2	Section 1350 Certification	

*Exhibit incorporated herein by reference as indicated or otherwise not filed.

†Exhibit constitutes a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

Exhibit 31.1

CERTIFICATIONS

I, Bobby S. Shackouls, certify that:

1. I have reviewed this report on Form 10-K of Burlington Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 28, 2005

Bobby S. Shackouls
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Steven J. Shapiro, certify that:

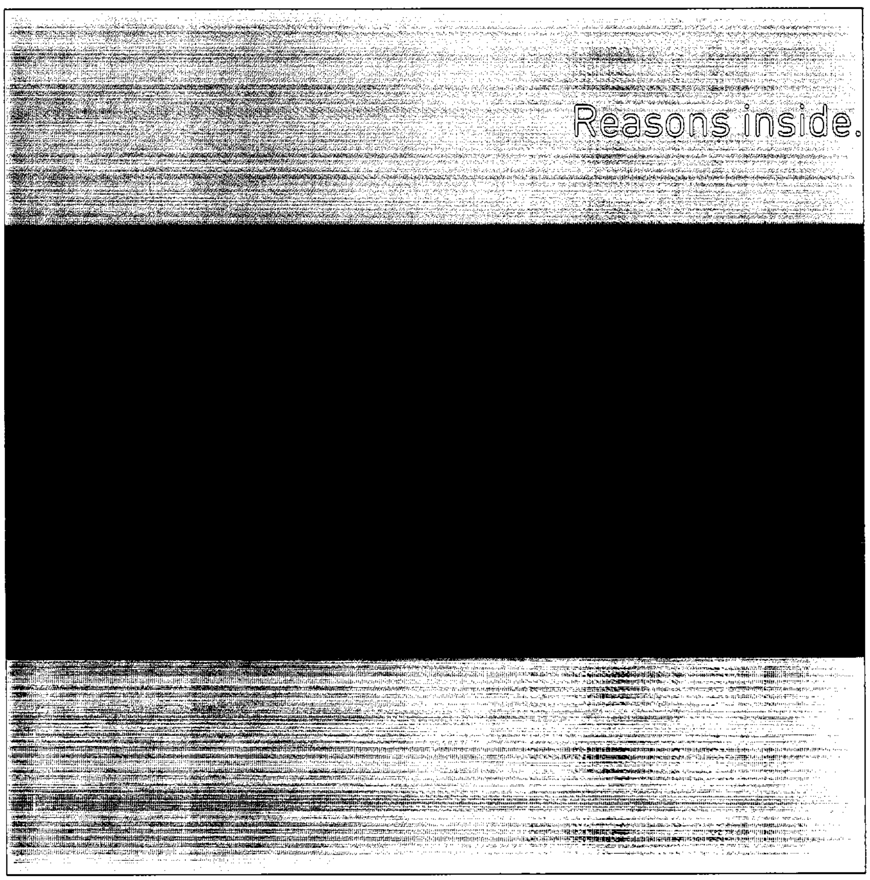
1. I have reviewed this report on Form 10-K of Burlington Resources Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 28, 2005

Steven J. Shapiro
Executive Vice President and
Chief Financial Officer

BURLINGTON RESOURCES 2004 ANNUAL REPORT

Why Burlington Resources?



BURLINGTON RESOURCES

Abbreviations used in this report

Bbls
Barrels

BCF
Billion Cubic Feet

BCFE
Billion Cubic Feet of Gas Equivalent

BOD
Barrels of Oil per Day

MBbls
Thousands of Barrels

MMBbls
Millions of Barrels

MCF
Thousand Cubic Feet

MCFE
Thousand Cubic Feet of Gas Equivalent

MMCF
Million Cubic Feet

MMCFD
Million Cubic Feet of Gas per Day

MMCFE
Million Cubic Feet of Gas Equivalent

MMCFED
Million Cubic Feet of Gas Equivalent per Day

TCF
Trillion Cubic Feet

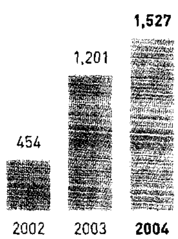
TCFE
Trillion Cubic Feet of Gas Equivalent

NGLs
Natural Gas Liquids

BURLINGTON RESOURCES

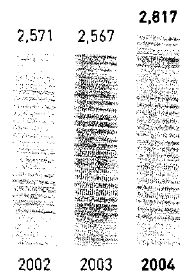
Burlington Resources Inc.
717 Texas Avenue, Suite 2100
Houston, Texas 77002-2712
(713) 624-9000
www.br-inc.com

Net Income
(Year Ended December 31 - $ Millions)



Total Reserves
(December 31 - TCFE)

Total Equivalent Daily Production
(Year Ended December 31 - MMCFE per day)



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Board of Directors and Officers **24**
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Form 10-K **26**

Financial & Operating Data

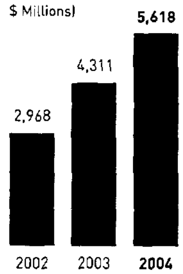
Financial Data	2004	2003	2002
	(In Millions, Except Per-Share Amounts and Ratios)		
Revenues	$ 5,618	$ 4,311	$ 2,968
Income before Income Taxes and Cumulative Effect of Change in Accounting Principle [a]	$ 2,304	$ 1,570	$ 569
Income before Cumulative Effect of Change in Accounting Principle [a] [c]	$ 1,527	$ 1,260	$ 454
Cumulative Effect of Change in Accounting Principle - Net [b]	$ —	$ (59)	$ —
Net Income [a] [b] [c]	$ 1,527	$ 1,201	$ 454
Basic Earnings per Common Share [a] [b] [c] [d]	$ 3.90	$ 3.02	$ 1.13
Diluted Earnings per Common Share [a] [b] [c] [d]	$ 3.86	$ 3.00	$ 1.13
Basic Weighted Average Common Shares [d]	392	398	402
Diluted Weighted Average Common Shares [d]	395	400	404
Net Cash Provided by Operating Activities	$ 3,436	$ 2,539	$ 1,549
Capital Expenditures	$ 1,747	$ 1,788	$ 1,837
Total Assets	$ 15,744	$ 12,995	$ 10,645
Total Debt	$ 3,889	$ 3,873	$ 3,916
Stockholders' Equity	$ 7,011	$ 5,521	$ 3,832
Total Debt to Total Capital Ratio	36%	41%	51%
Cash Dividends per Common Share [d]	$ 0.32	$ 0.29	$ 0.28

Operating Data	2004	2003	2002
Year-End Proved Reserves			
Natural Gas (BCF)	8,226	8,074	7,890
Natural Gas Liquids (MMBbls)	332.5	330.9	300.2
Crude Oil (MMBbls)	297.7	282.1	287.9
Total (BCFE)	12,007	11,752	11,418
Production			
Natural Gas (MMCF per day)	1,914	1,899	1,916
Natural Gas Liquids (MBbls per day)	65.3	64.8	60.1
Crude Oil (MBbls per day)	85.2	46.5	49.1
Total (MMCFE per day)	2,817	2,567	2,571
Average Sales Price			
Natural Gas (per MCF)	$ 5.49	$ 4.83	$ 3.20
Natural Gas Liquids (per Bbl)	$ 25.38	$ 20.40	$ 14.46
Crude Oil (per Bbl)	$ 36.25	$ 27.22	$ 24.11
Operating Costs & Administrative Costs (per MCFE)	$ 0.78	$ 0.68	$ 0.67
Wells Drilled (Net)	837.5	1,015	660
Percentage Successful	92%	88%	85%
Gross Wells Drilling at December 31	331	110	67
Net Wells Drilling at December 31	227	73	48

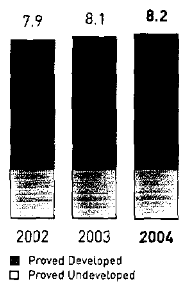
[a] Years 2004 and 2003 include non-cash pretax charges of $90 million ($59 million after tax, or $0.15 per share) and $63 million ($38 million after tax, or $0.09 per share) related to the impairment of oil and gas properties.
[b] Year 2003 includes a net loss of $59 million, or $0.15 per share, attributable to the cumulative effect of change in accounting principle related to the adoption of Statement of Financial Accounting Standards No. 143, Asset Retirement Obligations.
[c] Years 2004 and 2003 include income tax benefits of $23 million, or $0.06 per share, and $203 million, or $0.51 per share, respectively, related to the reduction of the Canadian federal income tax rate. Years 2004 and 2003 also include $45 million, or $0.11 per share, and $11 million, or $0.02 per share, respectively, related to the reduction of the Alberta provincial income tax rate. In 2004, the company recorded a U.S. income tax expense of $26 million, or $0.07 per share, related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004.
[d] Share amounts related to prior periods have been retroactively adjusted to reflect the 2-for-1 stock split of the company's common stock effective June 1, 2004.

Statistical Data

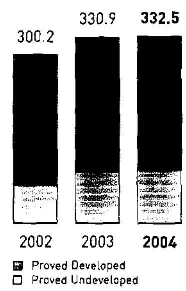
Total Revenues
(Year Ended December 31 - $ Millions)



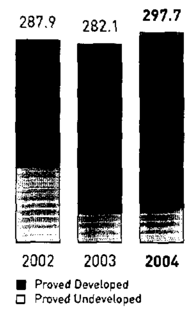
Natural Gas Reserves
(December 31 - TCF)



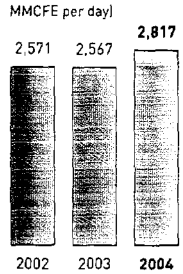
Natural Gas Liquids Reserves
(December 31 - MMBbls)



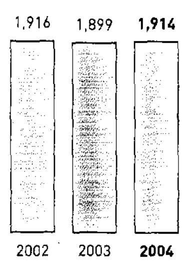
Crude Oil Reserves
(December 31 - MMBbls)



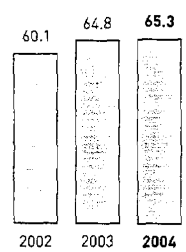
Total Equivalent Daily Production
(Year Ended December 31 - MMCFE per day)



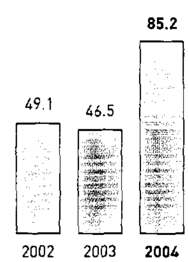
Natural Gas Production
(Year Ended December 31 - MMCF per day)



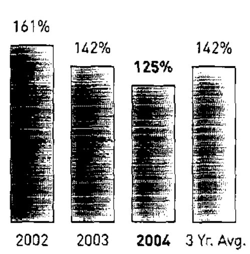
Natural Gas Liquids Production
(Year Ended December 31 - MBbls per day)



Crude Oil Production
(Year Ended December 31 - MBbls per day)

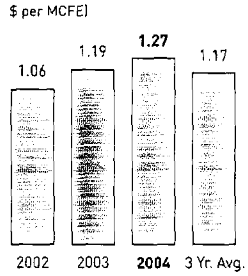


Reserve Replacement*
(Year Ended December 31 - Percent of Production)



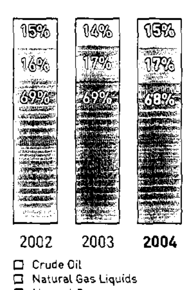
*Including Acquisitions

Reserve Replacement Costs*
(Year Ended December 31 - $ per MCFE)

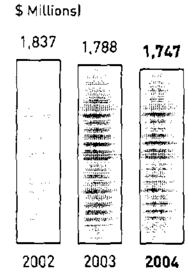


*Including Acquisitions

Proved Reserves by Product Composition
(December 31)

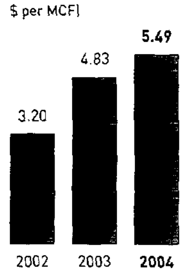


Capital Expenditures*
(Year Ended December 31 - $ Millions)

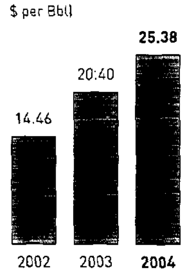


*Including Acquisitions

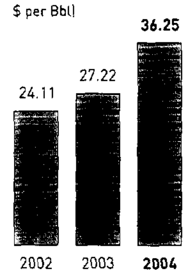
Realized Natural Gas Prices
(Year Ended December 31 - $ per MCF)



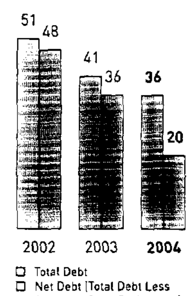
Realized Natural Gas Liquids Prices
(Year Ended December 31 - $ per Bbl)



Realized Crude Oil Prices
(Year Ended December 31 - $ per Bbl)



Debt to Total Capitalization (Percent)
(Year Ended December 31)



Our returns-and-growth strategy is showing its strength and underpinning our bright future.

Dear Burlington Resources Stockholders,

Burlington Resources enters 2005 with the greatest financial strength in our history, an excellent base of core assets that provides a stable and substantial foundation of production, and an opportunity portfolio with the potential to sustain our success.

We did not attain this position through our 2004 efforts alone. Indeed, the process began more than six years ago with a strategic decision to redirect our investments to pursue opportunities that offered both attractive returns on capital as well as volume growth. This was a bold step since producers were traditionally judged on growth alone, with little attention paid to returns. In fact, many regarded the two as mutually exclusive.

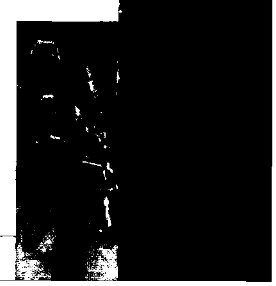
Subsequently, we sold assets in higher-cost areas that offered little growth potential and low returns, refocused our existing portfolio and acquired new properties in select areas where we had achieved the competitive advantages we call *Basin Excellence*SM. These areas consistently yielded higher returns.

Over the years, volatile commodity price cycles strengthened our resolve. During price weakness, our focus on these core areas helped maintain profitability and provided attractive acquisition opportunities. During price peaks, our consistent capital spending and field activity levels helped control our cost structure. We consistently improved Burlington's returns, and after halting an initial production decline, we are now achieving volume growth.

During 2004, as a favorable commodity price environment converged with rising investor appreciation of our strategy, Burlington stockholders realized a 59 percent return on investment in our common shares for the year, following a 31 percent return during 2003. Indeed, our shareholder returns led our industry peer group for the year as well as the most recent two-, three- and four-year periods. During 2004, we enacted a two-for-one stock split, increased our common stock dividends by 13 percent and returned additional capital to stockholders by repurchasing 14.4 million shares for $522 million on a post-stock-split basis.

The year also included these financial and operational achievements:

- Our company reported record financial results. Net income was $1.527 billion, or $3.86 per diluted share, compared to $1.201 billion, or $3.00 per diluted share, during 2003. Net cash provided by operating activities increased to a record $3.4 billion from $2.5 billion in 2003. Discretionary cash flow[1] was a record $3.3 billion, compared to the prior year's $2.6 billion.
- Return on capital employed[1] increased to 19.8 percent from 17.7 percent during 2003.
- We exceeded the upper end of our 3 percent to 8 percent average annual production growth objective as volumes increased 10 percent to 2,817 MMCFED from 2,567 MMCFED in 2003. Volumes grew in the Williston Basin, the Madden Field, South Louisiana, China offshore operations, Algeria and Ecuador. On a per-share basis, production increased 12 percent.
- We replaced 125 percent of 2004 production with new reserves at an average replacement cost[2] of $1.27 per MCFE, the lowest in our seven-company peer group. Total reserves increased to 12.0 TCFE at year-end 2004 from 11.8 TCFE the prior year.
- Our financial capabilities grew as total debt to total capitalization declined to 36 percent from 41 percent in 2003, and net debt to total capitalization[1] declined to 20 percent from 36 percent in 2003. At year-end 2004, our balance sheet included $2.2 billion in cash and cash equivalents, compared to $757 million at the close of 2003.



[1] *See tables on page 25 for reconciliations of the GAAP to non-GAAP measures used in calculating discretionary cash flow, return on capital employed and net debt to total capitalization.*

[2] *Reserve replacement cost was calculated by dividing total oil and gas capital costs, including acquisitions, of $1.644 billion, by the sum of reserve revisions, extensions, discoveries, other additions and acquisitions.*

"While 2004 was truly a remarkable year, it is time to look to the future and to sustaining our success. Despite our accomplishments, we will not become complacent."

- Our consistent investment approach continued, with capital expenditures totaling $1.75 billion compared to 2003 expenditures of $1.79 billion.
- Successful drilling established promising development programs in the Bossier natural gas trend in East Texas and the Bakken oil trend in Montana and North Dakota.
- Unit operating costs increased 12 percent during 2004 from 2003 as a result of industry-wide cost inflation for drilling and other well services. However, Burlington's costs were the lowest in our peer group.

While 2004 was truly a remarkable year, it is time to look to the future and to sustaining our success. The theme of this annual report, "Why Burlington Resources?" addresses the reasons for our belief that we can continue to prosper.

Despite our accomplishments, we will not become complacent. We believe that the quality of our asset portfolio will continue providing key competitive advantages. Further, we are determined to remain focused on our business fundamentals – uncompromising discipline throughout commodity price cycles, relentless attention to enhancing capital efficiency and controlling costs, and ongoing opportunity creation through continual upgrading and expansion of our drilling inventory.

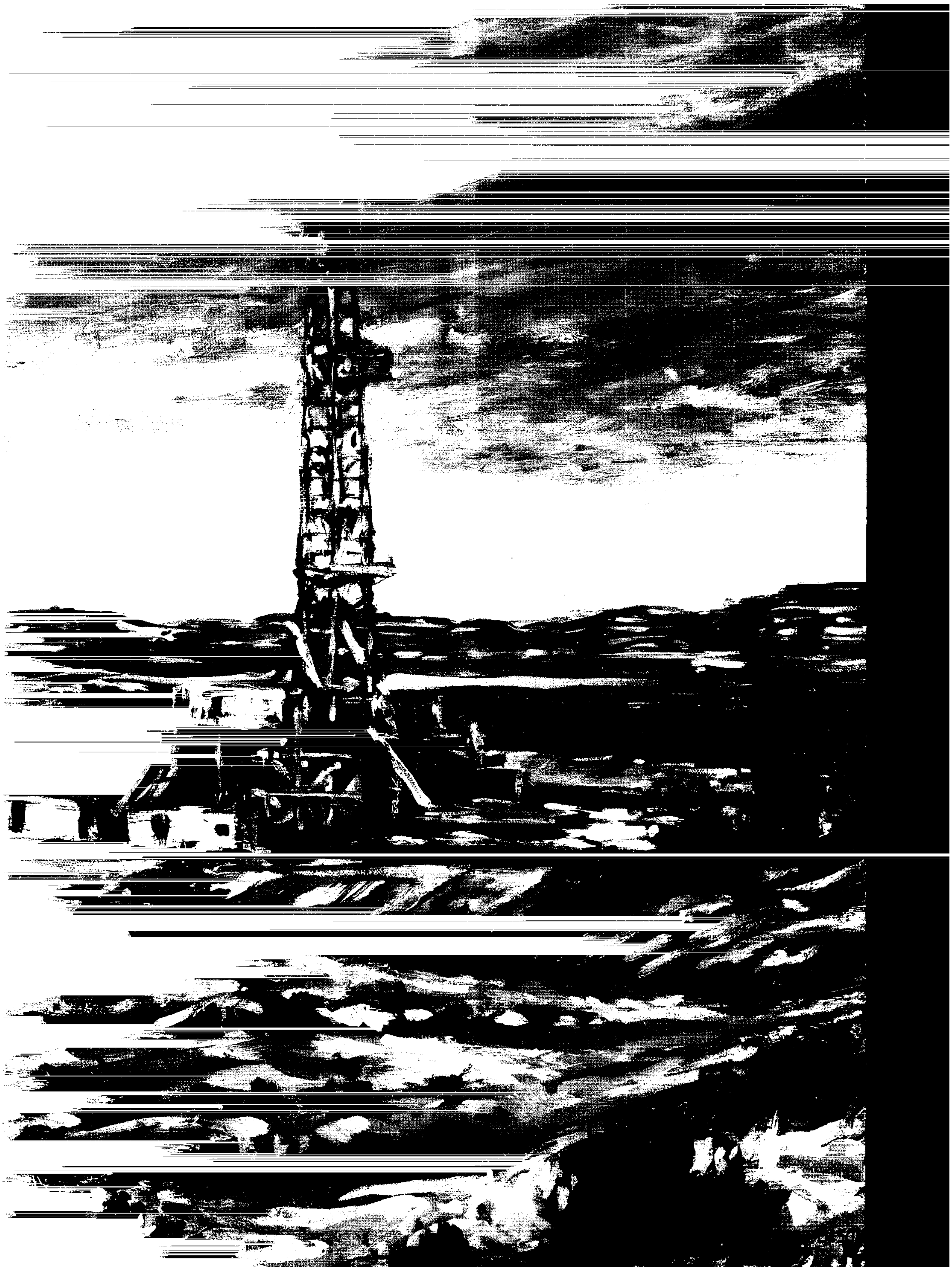
Consequently, we expect to achieve further production growth during 2005. We plan a capital budget of $2 billion excluding acquisitions, a 21 percent increase that we believe is modest considering Burlington's larger production base and rising industry service costs.

We intend to continue our focus on North America, with 88 percent of our 2005 investments allocated there, the vast majority for low-risk development and extension projects. Meanwhile, we will pursue opportunities to leverage our financial strength and thus further expand our opportunity portfolio and return capital to our shareholders.

In closing, I must compliment Burlington's employees for their discipline, dedication and innovation throughout these years of progress. Together, we foresee encouraging potential for 2005 and beyond. Finally, I must thank you, our stockholders, for your support and your conviction in positively responding to the question, "Why Burlington Resources?"

Bobby S. Shackouls

Bobby S. Shackouls
Chairman, President and Chief Executive Officer



We focus on continuously adding value in existing areas by identifying new resources from our vast core positions.

To discuss why Burlington's asset base is so effectively sustaining our success, we call upon:

Randy Limbacher, Office of the Chairman, Exec. VP and COO
Steve Shapiro, Office of the Chairman, Exec. VP and CFO
Mark Ellis, Sr. VP, North American Production
John Williams, Sr. VP, Exploration
Richard Fraley, VP, San Juan Division
Thomas Nusz, VP, International Division
Brent Smolik, President, Burlington Resources Canada Ltd.
Barry Winstead, VP, Mid-Continent Division

What makes Burlington's property base unique?
LIMBACHER: North America accounts for about 90 percent of our reserves, the majority of which are concentrated in just six major basins where we believe we have attained the advantages of *Basin Excellence*℠, which include lower costs, differential geologic and operating expertise and an established infrastructure. We were an early advocate of "resource capture" in areas that offer long-lived reserves and major production potential, particularly in the Rocky Mountain natural gas fairway. In fact, the San Juan Basin and the Deep Basin, the largest gas fields in the U.S. and Canada, are the fairway's bookends. We are the largest operator in both, and believe they exemplify properties in which our excellent resource positions, multiyear drilling inventories and sustained activity levels enable us to perform differentially on costs. Collectively, our properties exhibit an annual base production decline rate of under 20 percent, well below the industry average.

What is your production goal for 2005?
LIMBACHER: We are committed to a long-term goal of achieving 3 percent to 8 percent average annual production growth, and expect to perform within this range during 2005. We expect growth from the Williston Basin, South Louisiana, the Bossier and Bakken trends, the East Irish Sea and the scheduled start-up of the Swordfish Field in the deepwater Gulf of Mexico.

What are the biggest challenges to meeting your growth goals?
LIMBACHER: As a large company with a growing production base, we must continually analyze our portfolio and move the best prospects into development while replenishing and upgrading our inventory. We do this by adding opportunities in existing core areas, conducting exploration in new areas and making acquisitions. The latter two can require significant positioning investments. Our growth makes inventory reloading more difficult, but we believe we can meet this challenge.

Do you remain committed to North American natural gas?
LIMBACHER: Yes, because we believe the North American natural gas business is a great one. Although it is mature, growth is slow but steady, and the financial returns are among the highest in the global oil and natural gas industry. It also suits our core competencies of "manufacturing" gas in geologically complex reservoirs by

"We are committed to a long-term goal of achieving 3 percent to 8 percent average annual production growth, and expect to perform within this range during 2005."

conducting repeatable, large-scale, multiyear development programs – exactly the types of opportunities remaining on this continent.

What could threaten your North American natural gas strategy?

SHAPIRO: We see no credible short-term threats to the market. Supplies are tightening due to basin maturity, and large new sources will not emerge quickly. It would take years to significantly increase imports of liquefied natural gas or build pipelines to transport gas from Alaska or the Canadian Arctic, for example. Also, higher prices have had little impact on demand. Although the weather and the economy remain wild cards, we expect Burlington to operate profitably and perform differentially in any realistic price scenario.

What is your view of natural gas prices?

SHAPIRO: Tight supplies and higher industry costs have probably increased the floor price for natural gas to roughly $4.50 per MCF, and we believe prices will range from that level to perhaps $6.50, with potential for cyclical volatility. We are positioning Burlington to outperform our peers at any of these price levels, while creating significant upside for shareholders should prices remain high.

What is your hedging strategy?

SHAPIRO: We use hedging to capture peak prices for a portion of our production. For North American natural gas, we hedge no more than half of our production for no longer than two years. We use wide "collars" to provide a floor price that protects against downturns and a ceiling that allows our stockholders to participate in increases. This strategy yielded $180 million in incremental revenue from 2001 through 2004.

Describe Burlington's drilling inventory today.

LIMBACHER: Our goal is to maintain a five-year project inventory portfolio, focused mainly in large, continuous reservoirs undergoing concentric or infill development. Thorough analyses by our technical teams indicate that we now have at least that much inventory, with 8,900 net potential projects. Much of this inventory is geologically low in risk, and we believe it is highly economical at natural gas prices of $5 per MCF and oil prices of $30 per barrel.

Describe how you identify and categorize drilling inventory.

ELLIS: We employ a very rigorous process of assessing and cataloging inventory potential. We begin by integrating a geologic interpretation with an engineering evaluation, resulting in a resource assessment. Once the assessment is complete, we develop an operations plan and economically model the inventory on a risk-adjusted basis. We feel that we have a high-quality inventory set, with more than 3 TCFE characterized as proven undeveloped reserves.

Comment on the role of acquisitions in meeting your growth goals.

SHAPIRO: Our volume growth during 2004 came primarily from organic sources. Given our high-quality prospect inventory, we are not forced to pursue acquisitions to achieve our near-term goals. Indeed, we have exercised restraint during periods when the acquisition market became overheated. However to further replenish our long-term inventory, we are willing to consider transactions if the right ones come along. Our balance sheet strength provides the means to undertake transactions, both small and large. We expect to be a consolidator.

What criteria do you use in evaluating acquisitions?

SHAPIRO: First, potential acquisitions must fit our concept of *Basin Excellence*SM so that we can utilize our core skills of operating large-scale, repeatable, multiyear development programs. Second, they must offer upside development potential, not just add current production. And third, they must be priced realistically and must compete for capital on an economic basis against our other investment options – funding drilling programs and returning capital to stockholders through dividends and share repurchases.

What are your focus regions for acquisitions?

SHAPIRO: We primarily consider acquisitions in existing core areas, but will look elsewhere if the opportunities offer sufficient scale to allow us to attain *Basin Excellence*SM there as well.

How much longer can you achieve differential reserve replacement costs given your maturing asset base?

SHAPIRO: Although industry replacement costs are rising, we believe we can sustain our differential performance. Our 2004 replacement costs were the lowest in our seven-company peer group. Indeed, our costs in North America have been about 40 percent lower than peer averages in recent years. We believe this is due to the depth and quality of our project inventory and our efficient business processes. We expect these advantages to continue.

Do you have a strategy to buy back stock on an ongoing basis?

SHAPIRO: Our business model of generating sector-leading returns and modest volume growth is highly consistent with returning capital to stockholders through share repurchases and dividends. Repurchases help increase production per share, while their flexibility enables us to respond to volatility. They are an inexpensive way to acquire our own reserves, while preserving our balance sheet until acquisitions are priced more attractively. Since late 2000 we have repurchased nearly 62 million shares on a post-stock-split basis, with $952 million remaining at year-end 2004 in our current repurchase authorization. These buybacks were equivalent to a $1.6 billion reserve acquisition at an attractive unit cost of about $1.16 per MCFE[1].

Why are industry service costs rising?

LIMBACHER: The service industries are experiencing heavy demand prompted by a drilling upturn, so they can impose higher prices and pass along their own rising costs. This results in up to a 15 percent annual inflation rate, with wide regional variability.

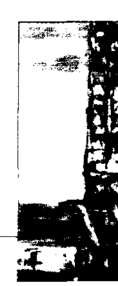
What are your strategies for mitigating service cost increases?

LIMBACHER: We intend to continue performing differentially on costs. To do so, we compare our company and divisional operating efficiency against that of our peers and establish performance benchmarks. We then strive to exceed those standards by improving our business processes. We also utilize global purchasing strategies and leverage our economies of scale to negotiate better prices for goods and services.

What measures ensure the reliability of your reserve estimates?

ELLIS: We begin with estimates from our internal reservoir engineers who are most familiar with the properties. A corporate engineering group provides audit and oversight, and then,

[1] See page 25 for an explanation of unit cost per MCFE of share repurchases.



"We believe the North American natural gas business is a great one. Although it is mature, the financial returns are among the highest in the global oil and natural gas industry, and it suits our core competencies."

independent audit firms review our estimates, as they have since Burlington became a public company in 1988. Currently one firm audits our Canadian reserves and another our U.S. and international reserves. These firms review at least 80 percent of our reserves annually.

Explain your unconventional resource play progress in 2004.

WILLIAMS: We established promising development positions in the Bossier trend in East Texas and the Bakken trend in Montana and North Dakota. In the Bossier, seven wells found commercial natural gas with production of 45 MMCFD net in early 2005, with prospects of doubling that rate by year-end. We plan about 20 wells during 2005 with a $120 million capital budget. In the Bakken, eight wells encountered oil on legacy acreage and by early 2005 were producing more than 3,000 BOD net. We expanded our acreage holdings and now plan about 20 wells during 2005 with a $50 million budget. Both trends hold significant potential. Meanwhile, in the Barnett Shale trend in North Texas, we added 90 wells, averaged production of 60 MMCFED net and tested the application of horizontal drilling. We plan approximately 60 wells during 2005 and are considering further downspacing and refracturing of older wells.

Describe key activities and results in the Williston Basin during 2004.

WINSTEAD: The East Lookout Butte and Cedar Hills South horizontally drilled waterflood programs exceeded expectations by producing 16,000 BOD net during 2004, up 60 percent from 2003, with a peak of about 35,000 BOD net anticipated around the 2007 timeframe. We accelerated our program during 2004 by drilling 39 producing wells and eight injection wells, with 48 wells planned during 2005. Drilling down to 160-acre spacing continues, with strong response to the waterflood. To sustain our growth beyond the 2007 timeframe, we are considering tertiary recovery.

Are your new South Louisiana properties performing as expected?

WINSTEAD: They are doing very well during the early stages of our initial 20-well drilling and 30-well recompletion programs, with production already responding. We have allocated $105 million in capital spending here during 2005.

What is the status of Madden Field production and development?

WINSTEAD: Following completion of gathering system repairs in mid-2004, natural gas sales from the Deep Madison zone increased to over 90 MMCFED net. The reservoir and processing plant are performing well and should support sustained production for a number of years. Meanwhile, Madden's shallower formations yielded average net production of 33 MMCFED, with Lower Fort Union development adding 52 new wells. Sixty wells are planned for 2005.

How long can the San Juan Basin maintain its production?

FRALEY: We expect to sustain volumes of 700 to 750 MMCFED net for the foreseeable future by continually assessing the potential contained in the basin's major producing horizons, adding infill wells and undertaking such optimization opportunities as gas compression and artificial lift. Investments will total about $150 million annually, depending on activity levels, illustrating the basin's value – it provides stable, large-scale production at relatively low capital cost.

Are there plans to accelerate drilling in the San Juan Basin?

FRALEY: We increased activity by 25 percent last year, and plan roughly 10 percent annual increases, but this will be difficult to implement because the drilling and service industries and government regulatory approval capabilities are already stretched thin. We drilled 164 operated wells in 2003 and 205 wells last year, with 220 wells planned during 2005. We recently committed to a new drilling rig, and are evaluating approaches to further increase capital spending and activity levels without eroding our returns.

How did you achieve the transition from growth to production maintenance in the San Juan Basin?

FRALEY: After serving as a growth engine for decades, the basin's advancing maturity means that fewer high-volume drilling opportunities remain. However, thousands of smaller-scale but attractive development opportunities are available, provided that costs can be controlled. We recognized the basin's new realities and evolved from a high-growth, capital-intensive culture into one built upon efficiency and continuous process improvement. By doing many things better, during 2004 we achieved a healthy increase in reserves and modest production growth, while remaining one of the basin's lowest-cost producers.

You diverted capital from Canada to the U.S. during 2004. What was the impact, and what are your 2005 plans?

SMOLIK: Even with the diversion, spending in Canada rose 18 percent last year, but we got less bang for the buck due to the weaker U.S. dollar and rising local drilling and service costs. In addition, a short winter followed by a wet summer hampered drilling and tie-in operations. We thus performed fewer development projects than planned and experienced a 6 percent production decline after several years of growth. We plan to slow that decline by increasing 2005 spending by 15 percent and drilling a record 945 gross wells, compared to 787 wells drilled or pending during 2004. We also accelerated the December ramp-up of winter drilling.

Are you concerned about margins in Canada given foreign exchange movements and higher costs?

SMOLIK: Although margins here do not match those in the U.S., they are still very attractive and are expected to remain so in any realistic scenario for commodity prices and exchange rates.

What is Canada's potential?

SMOLIK: We see Canada yielding major production and profitability for years to come, with some growth possible if exchange rates and service cost trends do not disrupt our investment plans. Western Canada's producing fields are relatively less mature than those in the U.S. We hold leases on 3.4 million net undeveloped acres, and resource assessments have confirmed ample potential to support higher activity levels in 2005 and beyond.

How is the Deep Basin performing?

SMOLIK: It continues supplying healthy volumes and new development potential. During 2004 we initiated significant resource assessments in the basin that increased our proven reserves and identified a half-dozen geologic formations that are worthy of additional focus. We also

"Our goal is to maintain a five-year project inventory portfolio. Technical analyses indicate that we now have at least that much, with 8,900 net potential projects."

achieved encouraging results from initial drilling on new acreage in the Brassey area.

Describe your key 2004 international accomplishments and focus areas for 2005.

NUSZ: We achieved a full year of production from three recently completed development projects and mechanically completed a fourth project. The Panyu project in the South China Sea outperformed expectations, contributing 19,000 BOD net. One of two satellite exploration projects succeeded, and during 2005 we expect to start a second phase of development and potentially drill two other exploration projects. In Algeria, the MLN Field exceeded expectations, averaging 11,000 BOD net and exiting the year at 14,000 BOD net. Including our production from the Ourhoud Field, Block 405a contributed 16,500 BOD net. Final engineering design is proceeding for expansion of the MLN facility over the next few years. In Ecuador, the Yuralpa Field contributed 4,000 BOD net. In the East Irish Sea, we initiated natural gas production from the Rivers Fields, and during early 2005 are working to resolve start-up issues in the processing facility. We are also advancing development of natural gas off the coast of Egypt.

What is the status of operations in Latin America?

NUSZ: We hold 5.5 million net acres of leases in South America, and that could increase during 2005. In Ecuador, production averaged 6,600 BOD net during 2004, and for the coming year drilling will continue on blocks 7 and 21. Negotiations continue with indigenous communities on blocks 23 and 24 in an effort to gain access for evaluation. Elsewhere along the Andean Mountain Front, we completed a 3-D seismic survey on Colombia's Orquidea Block, and plan an exploratory test on Peru Block 39 during 2005. In Argentina, natural gas production during 2004 was 23 MMCFD net.

Does the East Irish Sea offer further potential?

NUSZ: Yes. Near-term, we plan one to two development wells in the Millom and Dalton sweet gas fields, and an exploratory test at Asland that would extend the current field limits. In the Rivers complex the Calder Field is on stream, while the Darwen and Crossans fields await future development. We also plan to drill a potentially significant exploratory prospect, Kelly, during 2005.

What is the status of your onshore China operations?

NUSZ: We are delineating our resource position in the Bajiaochang Field and exploring other areas of the 1,700-square-mile Chuanzhong Block for natural gas. During 2004, we drilled four wells and completed a 3-D seismic survey. We also trained local personnel, improved the efficiency of our field operations and continued analyzing the producing formations. Up to eight wells are planned for 2005.

Our culture rewards achievement while continuously improving the business processes that will sustain our success.

To discuss why individual productivity is a key to sustaining our success, we call upon:

Mark Ellis, Sr. VP, North American Production
Ellen DeSanctis, VP, Investor Relations and Corporate Communications
Richard Fraley, VP, San Juan Division
Brent Smolik, President, Burlington Resources Canada Ltd.
Bill Usher, VP, Human Resources

Do you have sufficient staffing to carry out your programs?

USHER: Yes, in most areas. After several years of flat staffing at approximately 2,100 full-time employees, our larger scale and rising activity levels prompted growth to 2,200 employees. Attrition has been low except in Canada, where a tight industry labor market and a boom in new-company start-ups have caused some losses of personnel.

SMOLIK: Our Canadian staff plans a record drilling program in 2005, with even higher activity levels possible in the future. To ensure adequate staffing, we stepped up recruiting of both experienced personnel and recent college graduates, and expect our Canadian workforce to increase from the current 770 full-time employees to approximately 860 by year-end 2005.

How are you responding to the industry's perceived personnel shortages?

USHER: This is a universal concern in our industry. Since our focus is on continually enhancing the capabilities of our personnel, we are emphasizing career-long professional training and personal development. We are expanding college recruiting in terms of offers extended and techniques used to attract promising candidates, particularly at universities in or near our division cities. Finally, we are actively recruiting experienced personnel in a number of disciplines.

Are you impacted by worker shortages within the service industry?

SMOLIK: Availability of service personnel is a vital issue in Canada. Whenever we select drilling and service companies, we review their environmental and safety performance and consider their success at attracting and retaining stable, capable workforces, since both are keys to operational efficiency. To further mitigate the impact of worker shortages on our operations, we rely on our large inventory of capital projects, use advance scheduling and form long-term relationships with the better-performing companies.

FRALEY: From time to time in the San Juan Basin, we find that rigs may be down for a day or so due to lack of personnel. In fact, turnover across the entire service sector is a significant issue. We have helped service firms analyze the causes of their employee turnover and worked with them to remedy the situation, but this appears to be an ongoing issue that is not unique to the San Juan Basin. We hope that the industry's increased activity levels and improved

"We are not resting on our laurels. The cultural transformation of Burlington continues with the goal of elevating our efficiency and effectiveness."

financial performance will enable these firms to address their personnel problems.

Do you have a performance-based compensation program, and if so, what metrics drive it?

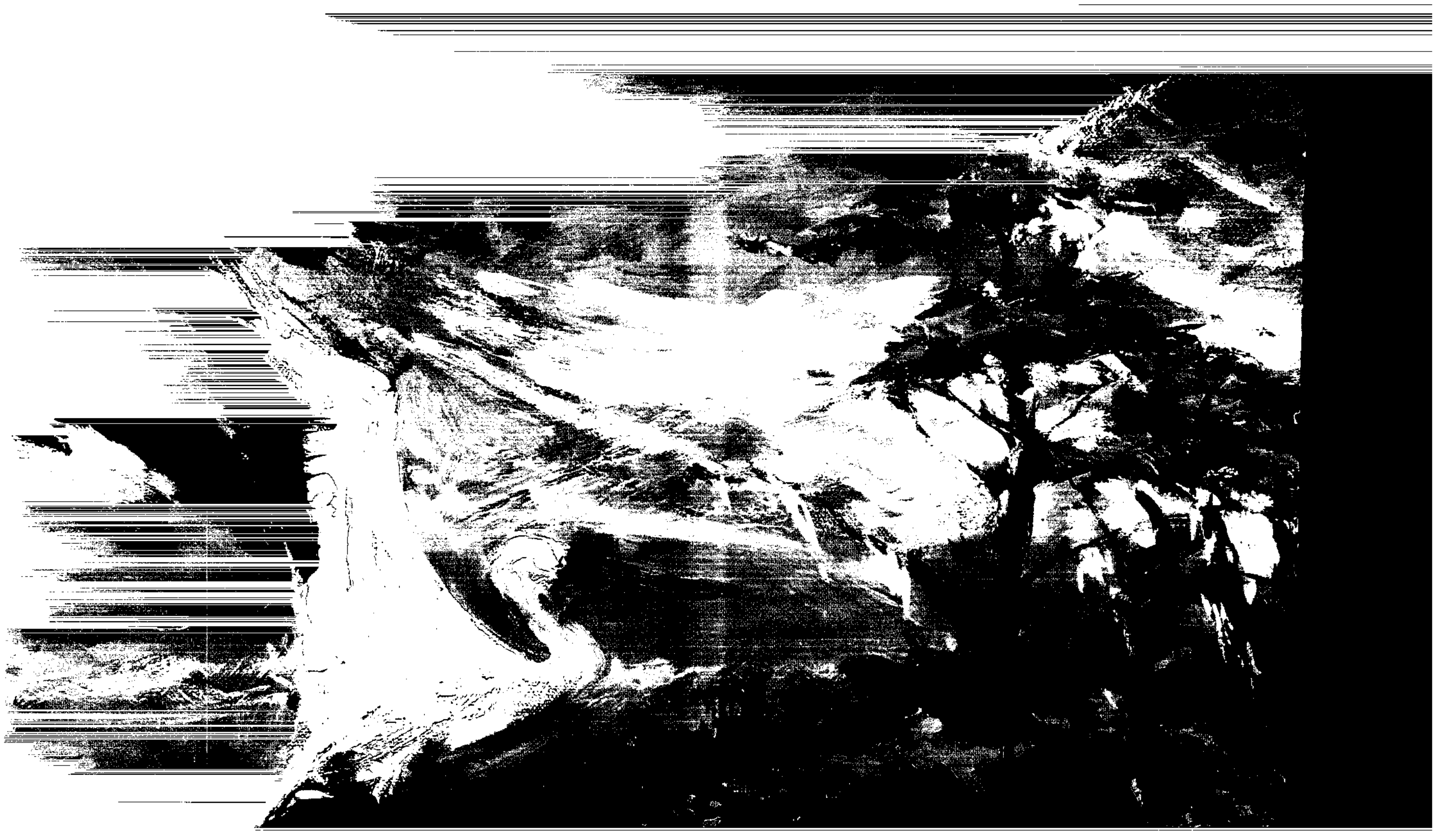
USHER: Our *Alignment to Value* program creates incentives to maintain employee focus on overall business objectives. The program sets annual bonus targets based on personal, company and, where appropriate, divisional performance. Metrics considered include Burlington's return on capital employed; unit cash costs; production growth per share; change in appraised net worth per share; reserve replacement costs; total shareholder return; and environmental, health and safety (EH&S) performance. Divisional targets are set for production, financial results, drilling and EH&S performance.

How does Burlington share knowledge among its operating divisions?

ELLIS: We utilize joint work projects, specialized staff conferences, training sessions and the People Skills database that showcases individual employee expertise. We also share best practices. For example, we now have nearly 50 resource assessments under way throughout Burlington based on a concept developed in the San Juan Division. Each assessment focuses on specific producing formations in a major field. Our assessment teams use existing well data to conduct geologic mapping that shows original hydrocarbons in place, and then analyze the reservoirs to determine recovery potential. Next, these teams develop operational plans for well placement, completion design and facility needs, then economically model expected production rates, costs and commodity prices over the project life spans.

What are you doing to improve efficiency?

DeSANCTIS: We are not resting on our laurels. The cultural transformation of Burlington continues with the goal of elevating our efficiency and effectiveness. During 2004, we began 12 initiatives aimed at driving excellence in the key business skills that we believe are critical for our success. From an operations perspective, these initiatives center on inventory development and tracking as well as drilling and completions excellence. We are also working to improve corporate supply chain management, personnel development and strategic planning analytics. Each initiative has an executive sponsor and timeline, and we expect to see results in a number of areas beginning in 2005.



Our business performance is strongly linked to values that demand respect for people, our communities and the environment.

To discuss why Burlington regards its corporate reputation as a prerequisite to sustaining our success, we call upon:

Joe McCoy, VP, Controller and Chief Accounting Officer
Thomas Nusz, VP, International Division
Frederick Plaeger, VP and General Counsel
Gavin Smith, VP, Corporate Affairs
Matt McEneny, Director, Environmental, Health & Safety

In a year of record earnings, how did your operations contribute to national economic capacity and growth?
McCOY: In addition to supplying the natural gas and crude oil that power modern life, we paid $165 million in federal and state income taxes, $109 million in other state and provincial taxes, approximately $200 million in severance taxes and $920 million in production royalties, while incurring $371 million in deferred tax liability. We also reinvested $1.7 billion of capital into our business, thus supporting goods and services providers that employ thousands of people. In addition, we returned approximately $640 million to stockholders in the form of dividends and share repurchases.

What were your charitable contributions in 2004?
SMITH: The Burlington Resources Foundation donated $5.7 million during 2004 to a variety of human services, educational, health care, civic, cultural and youth initiatives in the communities in which our employees live and work.

What role did employees play in your communities?
SMITH: Hundreds of Burlington employees regularly assist charitable and community organizations with their fund-raising efforts. They also volunteer for such initiatives as building homes for the needy, performing maintenance and cleanup, assisting the elderly, serving as school volunteers and carrying out a host of other activities. Burlington employees personally donated more than $1 million, which the foundation matched.

How is Burlington meeting stricter corporate governance standards?
McCOY: When Congress passed the Sarbanes-Oxley Act in 2002 to restore public confidence in corporate financial reporting, we viewed it as an opportunity to further enhance our control processes. During 2002, our chief executive and chief financial officers began certifying the accuracy of our financial statements, as the act required. In 2004, Section 404 of the act required public companies to provide an assertion to the effectiveness of their internal controls. Management concluded that our internal control over financial reporting was effective, and our audit firm provided a nonqualified audit opinion confirming management's assessment. This culminated a year of work by hundreds of employees to document and test more than 500 significant controls.

"We have an admirable record of conducting business ethically and legally. Our management clearly supports doing business the right way."

PLAEGER: We believe that we have an admirable record of conducting business ethically and legally. Our management clearly supports doing business the right way, and the board's audit committee makes compliance with our Code of Conduct a regular part of its agenda.

Are public expectations of corporate responsibility changing?

McENENY: The public increasingly expects corporations to contribute to the betterment of society in noneconomic ways that range from environmental protection to human rights, and to help meet social needs that may not be addressed by government. Our social practices include comprehensive environmental policies, a commendable charitable contributions program and extensive employee volunteer efforts. Additionally, in response to society's rising expectations, during 2004 we commissioned a corporate social responsibility initiative to formalize our relevant practices and assess whether changes are needed.

How do you protect the rights of indigenous peoples?

McENENY: Burlington has a comprehensive indigenous rights policy that requires us to consult with duly recognized indigenous leaders prior to initiating activity, provide appropriate compensation for property, apply proper operating practices, assist with community support and development programs, protect public health and safety, and minimize disturbance of culturally sensitive sites. This policy is based on internationally recognized standards.

What is the status of the disputed exploration blocks in Ecuador?

NUSZ: As operator of Block 24, Burlington, in close cooperation with the Ecuadorian government, is consulting with the official leaders of the federations, associations and communities representing the block's indigenous residents. We hope to gain their formal approval to conduct exploration, and have publicly stated that we will not proceed without majority approval. We have not set a deadline for this process. Block 23's operator is responsible for similar negotiations. We have repeatedly affirmed our commitment to consultation and our opposition to the use of force to gain access.

Does antidrilling sentiment in the western U.S. threaten your programs there?

PLAEGER: We believe that most local residents know that we are committed to being good neighbors. Although activist groups have received media coverage of their objections to drilling and have even filed lawsuits to block development, we believe these groups do not represent the majority. To date, they have caused only limited disruptions. We will continue listening to our stakeholders while striving to conduct our operations in a responsible manner that meets or exceeds legal requirements.

BOARD OF DIRECTORS

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Former Senior Advisor
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Partner
Phelps Dunbar LLP

Laird I. Grant [1]
Managing Director
U.S. Trust Company

Robert J. Harding [1][3]
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John T. LaMacchia [2]
Chairman
Tellme Networks, Inc.

Randy L. Limbacher
Office of the Chairman,
Executive Vice President
and Chief Operating Officer
Burlington Resources Inc.

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and Chief Executive Officer
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and U.S. Trust Corporation

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and Chief Executive Officer
Entech Enterprises, Inc.

Walter Scott Jr. [2][3]
Chairman
Level 3 Communications, Inc.

Bobby S. Shackouls
Chairman of the Board, President
and Chief Executive Officer
Burlington Resources Inc.

Steven J. Shapiro
Office of the Chairman,
Executive Vice President
and Chief Financial Officer
Burlington Resources Inc.

William E. Wade Jr. [2]
Retired President
Atlantic Richfield (ARCO)

(1) Audit Committee
(2) Compensation Committee
(3) Governance and Nominating Committee

OFFICERS

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Chairman of the Board,
President and Chief Executive Officer

Randy L. Limbacher
Office of the Chairman,
Executive Vice President
and Chief Operating Officer

Steven J. Shapiro
Office of the Chairman,
Executive Vice President
and Chief Financial Officer

Mark E. Ellis
Senior Vice President,
North American Production

L. David Hanower
Senior Vice President,
Law and Administration

John A. Williams
Senior Vice President, Exploration

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Vice President, Investor Relations
and Corporate Communications

M. Richard Diaz
Vice President
and Chief Information Officer

Richard E. Fraley
Vice President, San Juan Division

Daniel D. Hawk
Vice President and Treasurer

C. Scott Kirk
Vice President, Marketing

Gregory M. Larberg
Vice President and Chief Geologist

Joseph P. McCoy
Vice President, Controller
and Chief Accounting Officer

Thomas B. Nusz
Vice President, International Division

Frederick J. Plaeger II
Vice President and General Counsel

Gavin H. Smith
Vice President, Corporate Affairs

Brent J. Smolik
President
Burlington Resources Canada Ltd.

William B. Usher
Vice President, Human Resources and
Administration

Dane E. Whitehead
Senior Vice President
and Chief Financial Officer
Burlington Resources Canada Ltd.

Barry J. Winstead
Vice President, Mid-Continent Division

CORPORATE INFORMATION

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www.br-inc.com

Annual Meeting
The Annual Meeting of Stockholders
will be in Houston, Texas, on April 27, 2005.

Common Stock Listings
New York Stock Exchange
Symbol: BR

Stock Transfer Agent and Registrar
EquiServe Trust Company, N.A.
P.O. Box 43010
Providence, RI 02940-3010
(800) 736-3001
www.equiserve.com

Additional copies of this Annual Report
on Form 10-K filed with the Securities
and Exchange Commission are available,
without charge, by writing or calling:

Investor Relations
Burlington Resources Inc.
P.O. Box 4239
Houston, Texas 77210
(800) 262-3456

FORWARD-LOOKING STATEMENT

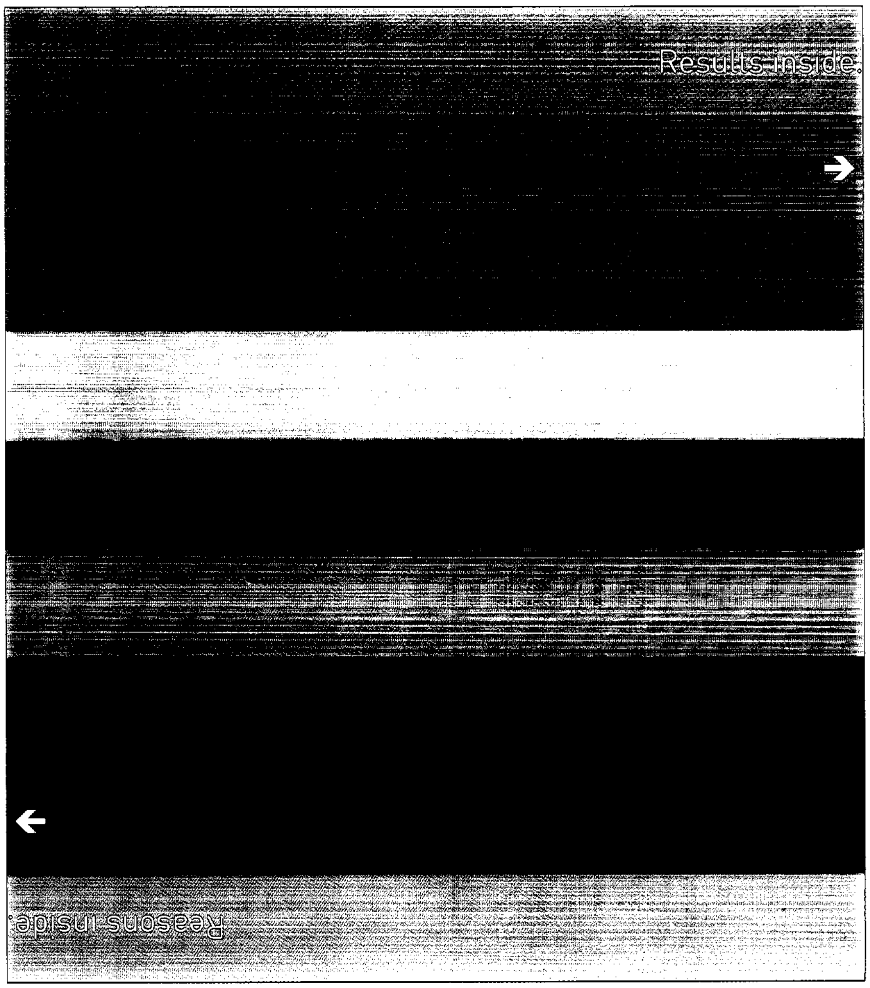
The company may, in discussions of its future plans, objectives and expected performance in periodic reports filed by the company with the Securities and Exchange Commission (or documents incorporated by reference therein) and in written and oral presentations made by the company, include projections or other forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 or Section 21E of the Securities Exchange Act of 1934, as amended. Such projections and forward-looking statements are based on assumptions that the company believes are reasonable, but are by their nature inherently uncertain. In all cases, there can be no assurance that such assumptions will prove correct or that projected events will occur, and actual results could differ materially from those projected.

CERTIFICATION STATEMENT

The New York Stock Exchange's Rule 303A.12(a) requires chief executive officers of listed corporations to certify that they are not aware of any violations by their company of the exchange's corporate governance listing standards. This annual certification by the chief executive officer of Burlington Resources Inc. has been filed with the New York Stock Exchange.

BURLINGTON RESOURCES

Why Burlington Resources?



Why Burlington Resources?

BURLINGTON RESOURCES

RECONCILIATION OF GAAP* TO NON-GAAP MEASURES

***GAAP - Generally Accepted Accounting Principles**
($ in Millions)

Net cash provided by operating activities to discretionary cash flow

	Full Year	
	2004	2003
Net cash provided by operating activities	$ 3,436	$ 2,539
Adjustments:		
Working capital	(54)	83
Changes in other assets & liabilities	(40)	(22)
Discretionary cash flow	$ 3,342	$ 2,600

Return on capital employed (ROCE)

Net Income - 2004	$ 1,527
Add: interest expense after tax	187
Earnings before after-tax interest expense	$ 1,714

	Dec. 31, 2004	Dec. 31, 2003
Total debt (GAAP)	$ 3,889	$ 3,873
Less: cash & cash equivalents	2,179	757
Net debt (non-GAAP)	1,710	3,116
Stockholders' equity	7,011	5,521
Total adjusted capital	8,721	8,637
Plus: cash & cash equivalents	2,179	757
Total capital	$ 10,900	$ 9,394

ROCE (GAAP)	16.9%
Impact of cash and cash equivalents	2.9%
ROCE (non-GAAP)	19.8%

Total debt to total capital to net debt to total capital

	Dec. 31, 2004
Total debt	$ 3,889
Stockholders' equity	7,011
Total capital	$10,900
Total debt	$ 3,889
Adjustment:	
Less: cash & cash equivalents	2,179
Net debt	$ 1,710
Net debt	$ 1,710
Stockholders' equity	7,011
Total adjusted capital	$ 8,721
Total debt to total capital ratio	36%
Adjustment:	
Less: impact of cash & cash equivalents	16%
Net debt to total capital ratio	20%

Unit cost per MCFE of share repurchases

As used herein, unit cost per MCFE of share repurchases is calculated by dividing enterprise value (market capitalization plus net debt) by total proved reserves, weighted based on the number of shares repurchased per year.

Why Burlington Resources?