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BURLINGTON RESOURCES 2003 ANNUAL REPORT

CONSISTENT

REASONS

BURLINGTON
RESOURCES

2003

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

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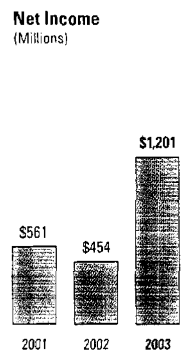
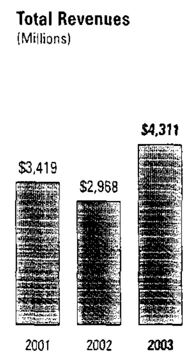
"We carried to our bottom line much of the commodity price gains, resulting in the highest net income in our history as well as the highest return on capital employed among our industry peers."

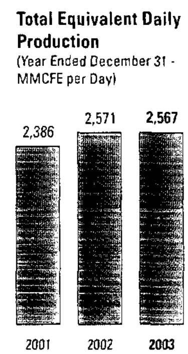
"Our core business will remain North American natural gas. Considering the market's exceptional strength, we believe that our strategic focus is just right."

"Every employee has individual goals that in turn support our divisional and company objectives."

"We believe in improving the well-being of the communities in which our employees live and work."







Dear Burlington Resources Stockholders,

I am pleased to report that 2003 was a highly successful year at Burlington Resources, and that we enter 2004 with a superb asset base, a sound business strategy, outstanding people and the respect of the communities in which we live and work. Thus, our vision of achieving production growth as well as sector-leading returns endures. Our reasons remain consistent, and our results continue to meet expectations. I look forward to many more achievements in the years to come.

Bobby Shackouls

FINANCIAL & OPERATING DATA

Financial Data	2003	2002	2001
	(In Millions Except Per-Share Amounts and Ratios)		
Revenues	$ 4,311	$ 2,968	$ 3,419
Income before Income Taxes and Cumulative Effect of Change in Accounting Principle [a]	$ 1,570	$ 569	$ 907
Income before Cumulative Effect of Change in Accounting Principle [a]	$ 1,260	$ 454	$ 558
Cumulative Effect of Change in Accounting Principle - Net [b]	$ (59)	$ —	$ 3
Net Income [a] [c]	$ 1,201	$ 454	$ 561
Basic Earnings per Common Share [a] [b] [c]	$ 6.03	$ 2.26	$ 2.71
Diluted Earnings per Common Share [a] [b] [c]	$ 6.00	$ 2.25	$ 2.70
Basic Weighted Average Common Shares	199	201	207
Diluted Weighted Average Common Shares	200	202	208
Cash Flows from Operations	$ 2,539	$ 1,549	$ 2,106
Capital Expenditures	$ 1,788	$ 1,837	$ 3,454
Total Assets	$ 12,995	$ 10,645	$ 10,582
Total Debt	$ 3,873	$ 3,916	$ 4,337
Stockholders' Equity	$ 5,521	$ 3,832	$ 3,525
Total Debt to Total Capital Ratio	41%	51%	55%
Cash Dividends per Common Share	$ 0.58	$ 0.55	$ 0.55

Operating Data	2003	2002	2001
Year-End Proved Reserves			
Natural Gas (BCF)	8,074	7,890	7,925
Natural Gas Liquids (MMBbls)	330.9	300.2	275.4
Crude Oil (MMBbls)	282.1	287.9	371.9
Total (BCFE)	11,752	11,418	11,808
Production			
Natural Gas (MMCF per day)	1,899	1,916	1,724
Natural Gas Liquids (MBbls per day)	64.8	60.1	47.1
Crude Oil (MBbls per day)	46.5	49.1	63.2
Total (MMCFE per day)	2,567	2,571	2,386
Average Sales Price			
Natural Gas (per MCF)	$ 4.83	$ 3.20	$ 4.03
Natural Gas Liquids (per Bbl)	$ 20.40	$ 14.46	$ 16.79
Crude Oil (per Bbl)	$ 27.22	$ 24.11	$ 23.45
Production and Processing & Administrative Costs (per MCFE)	$ 0.68	$ 0.67	$ 0.75
Wells Drilled (Net)	1,015	660	550
Percentage Successful	88%	85%	85%
Gross Wells Drilling at December 31	110	67	41
Net Wells Drilling at December 31	73	48	31

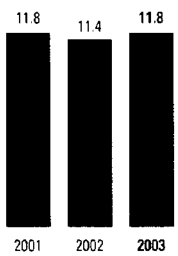
[a] Included in 2003 and 2001 are non-cash, pretax charges of $63 million ($38 million after tax, or $0.19 per share) and $184 million ($116 million after tax, or $0.56 per share), respectively, related to the impairment of oil and gas properties. Included in 2002 is a pretax gain of $68 million ($46 million after tax, or $0.23 per share) related to gain on disposal of assets.

[b] Amount in 2002 is related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, *Asset Retirement Obligations* ($0.30 per share) and amount in 2001 is related to the adoption of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended ($0.01 per share).

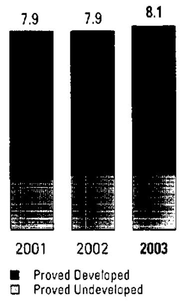
[c] Year 2003 also included an adjustment of $203 million, or $1.02 per share, related to the Canadian federal income tax rate reduction.

STATISTICAL DATA

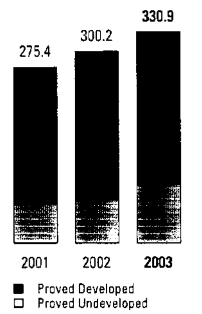
Total Reserves
(December 31 - TCFE)



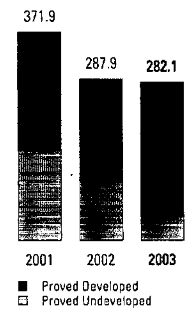
Natural Gas Reserves
(December 31 - TCF)



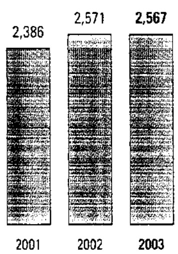
Natural Gas Liquids Reserves
(December 31 - MMBbls)



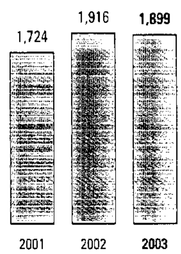
Crude Oil Reserves
(December 31 - MMBbls)



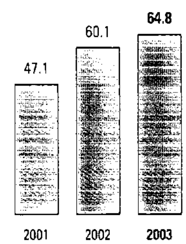
Total Equivalent Daily Production
(Year Ended December 31 - MMCFE per Day)



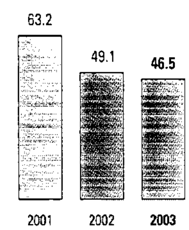
Natural Gas Production
(Year Ended December 31 - MMCF per Day)



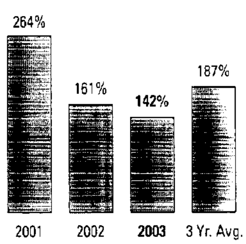
Natural Gas Liquids Production
(Year Ended December 31 - MBbls per Day)



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

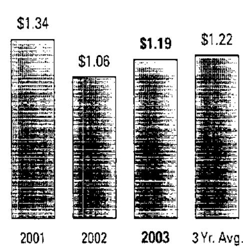


Reserve Replacement*
(Year Ended December 31 - Percent of Production)



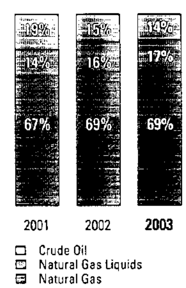
*Including Acquisitions

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

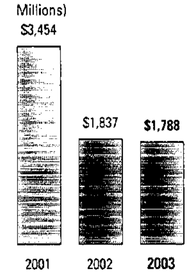


*Including Acquisitions

Proved Reserves by Product Composition
(December 31)



Capital Expenditures*
(Year Ended December 31 - Millions)



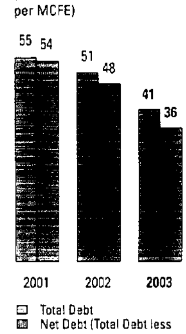
*Including Acquisitions

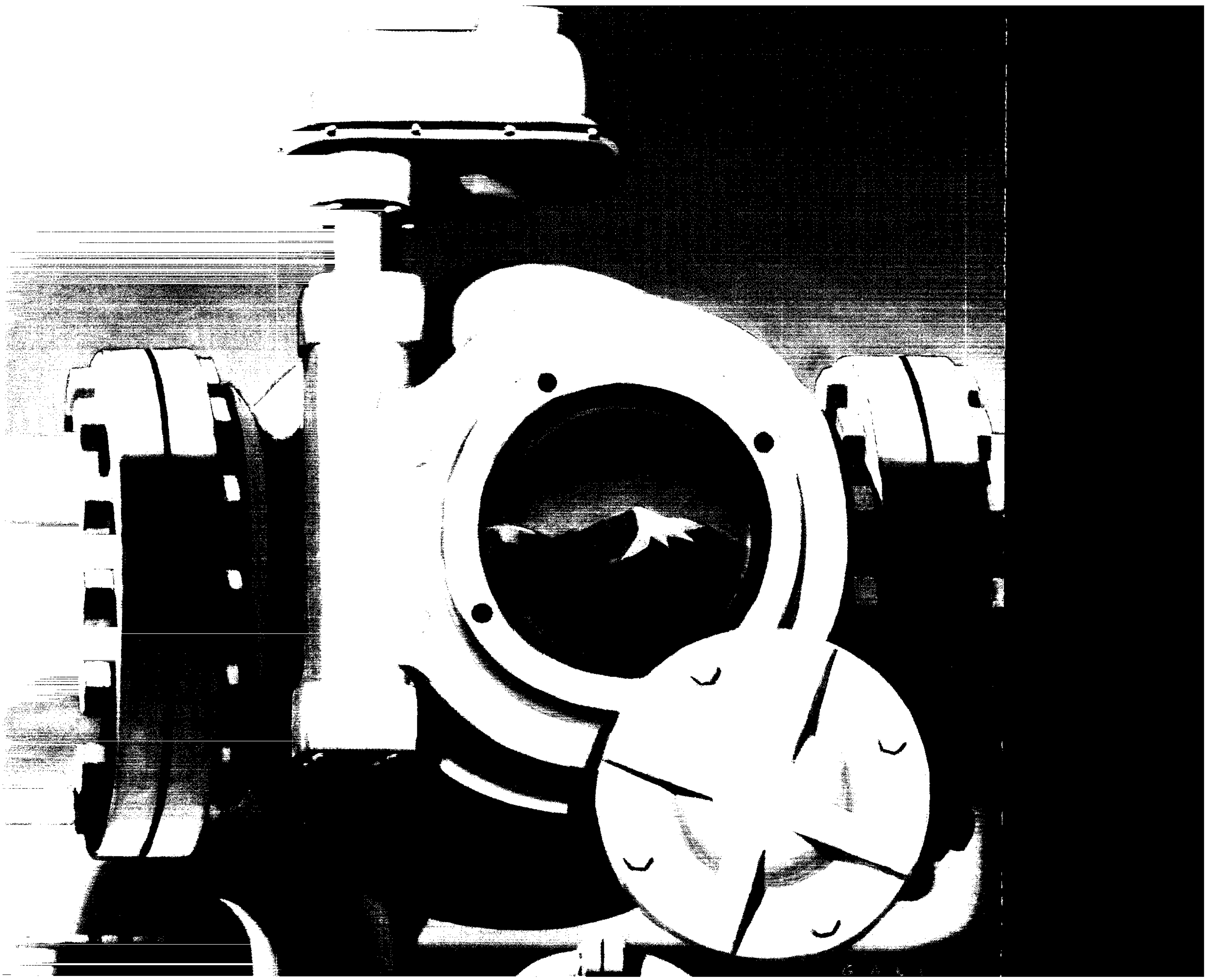
Realized Natural Gas Prices
(Year Ended December 31 - per MCF)

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 - per MCFE)





OUR VISION ENDURES

The North American natural gas business proved its sustainability and resiliency during 2003. Burlington Resources' strategic focus on this sector ideally positioned our company to prosper from the exceptionally strong commodity markets we witnessed during the year. We expect the markets to show continued strength in the future.

During 2003, the *Basin Excellence* concept that links our strategy to our asset base helped us exercise capital discipline and rigorous cost control despite industry service cost inflation and unfavorable foreign currency exchange fluctuations. Thus, we carried to our bottom line much of the commodity price gains that occurred during the year, resulting in the highest net income in our history as well as the highest return on capital employed among our industry peers.

We are now entering what we believe will be an era of significant production growth for Burlington, driven by the startup of several major development projects and the ongoing performance of our core producing properties. We have reaffirmed our goal of averaging 3 percent to 8 percent annual production growth over the next several years, and in fact expect to perform at the upper end of this range in 2004.

Our progress during 2003 drew growing investor attention, with Burlington's stockholders realizing returns of 31.4 percent on their investments in our common shares during the year, exceeding the performance of the Standard & Poor's 500 index. Bolstering this performance was a 9 percent increase in the cash dividend paid on our common stock during the year. Total shares outstanding declined to 197.6 million at year-end as a result of our ongoing share repurchase program, in which we reacquired 7.4 million shares during 2003.

Further, our performance over the past three years has been highly differential, with Burlington being one of only two companies among our industry peers to show positive total shareholder returns over the period.

> "Our progress during 2003 drew growing investor attention, with Burlington's stockholders realizing returns of 31.4 percent on their investments in our common shares during the year."

Listed below are Burlington's significant financial and operational highlights for 2003:

- Net income more than doubled to a record $1.201 billion in 2003, or $6.00 per diluted share, from $454 million, or $2.25 per diluted share, in 2002. Discretionary cash flow[1] during the year increased to a record $2.6 billion.
- Production averaged 2,567 MMCFED, essentially flat compared to 2002, as the year's volumes reflected the sale during 2002 of properties that yielded nearly 10 percent of our production. However, volume growth from "keeper" assets largely offset the sales. By year-end 2003, daily production was 18 percent higher than at year-end 2002.
- Return on capital employed[1] was 17.7 percent during 2003, nearly double the 9 percent return that Burlington earned in 2002.
- We replaced 142 percent of 2003 production with new reserves at an average cost of $1.19 per MCFE, continuing our excellent record. From 2000 through 2002, our reserve replacement costs averaged $1.18 per MCFE. Total reserves at year-end 2003 increased 3 percent to 11.8 TCFE from 11.4 TCFE the previous year, and grew approximately 5 percent on a per-share basis. We have a long, 12-year reserve-life index.
- Our cost control efforts are working. We are benefiting from acquisitions in recent years of properties with low production costs, and from the sale of higher-cost, non-core assets. Meanwhile, we have evolved a culture of cost awareness that we expect to yield long-term savings that should in turn improve our capital efficiency.
- Past investments in major international development programs are helping drive near-term growth. Crude oil production began in mid-2003 from Algeria's MLN Field, and later in the year from China's Bootes and Ursa Fields and from Ecuador's Yuralpa Field. We also anticipate the midyear start-up of natural gas production from the Rivers Fields in the East Irish Sea.
- Although we were disappointed by the deferred production volumes necessitated by repairs on the sour gas pipelines serving the Madden Field's Deep Madison formation, we believe that we acted prudently to address the issues encountered. Our election to reduce

production rates protected our employees and neighbors as well as the environment. We are performing the repairs safely and effectively. We restored much of our production by year-end and expect to achieve full deliverability by mid-2004.

- Technological innovation and diligent cost control made possible new drilling and production increases in several older operating areas, such as South Louisiana and the Deep Basin of Canada. We expect similar opportunities to help fuel future growth. Meanwhile, crude oil volumes continue rising from the horizontally drilled waterflood programs in the Cedar Hills and East Lookout Butte Fields in North Dakota and Montana.
- Last, our balance sheet exhibits rising strength, with $757 million in cash and cash equivalents on hand at year-end 2003. Total debt to total capitalization stood at 41 percent, down from 51 percent the year before. And net debt to total capitalization[1] fell to 36 percent from 48 percent the previous year, reaching the same level it was before the Canadian Hunter acquisition. We essentially paid for that transaction in just two years.

Looking ahead, we anticipate rising production volumes as we apply the disciplined, measured investment and operational approaches that underpin our strategy and business model. We plan $1.5 billion in exploration and production capital investments in 2004, essentially flat compared with 2003. Roughly 85 percent is intended for North American projects as international capital investments decline with the completion of our major development projects.

Even while benefiting from the current strength in the natural gas market, we remain keenly aware that in this cyclical commodity business, a downturn could always loom around the corner. Although we believe that a market downturn would be short-lived, our low-cost, full-cycle approach to the business and our high-quality asset base should enable Burlington to succeed in any likely market environment and to pursue the opportunities that will inevitably emerge during down-cycles. Our goal is to lead our peers in financial returns throughout the price cycles.

I extend my sincere appreciation to Burlington's employees for their contributions to our success, and to our stockholders for their ongoing support.

Bobby S. Shackouls

Chairman, President and Chief Executive Officer

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

OUR ASSETS EXCEL

Our success at Burlington Resources begins with our asset base, which is highly concentrated in core properties in which we have achieved *Basin Excellence*. We believe that our assets excel, and that we excel in exploiting them.

OUR ASSETS EXCEL

Offering their observations on the 2003 performance of our asset base, as well as on our prospects for the future, are:

Randy Limbacher, Office of the Chairman, Exec. VP and COO

Steve Shapiro, Office of the Chairman, Exec. VP and CFO

Mark Ellis, President, Burlington Resources Canada

Richard Fraley, VP, San Juan Division

Tommy Nusz, VP, International Division

Barry Winstead, VP, Mid-Continent Division

What is *Basin Excellence*?

LIMBACHER: *Basin Excellence* means concentrating our operations and expertise in high-potential core areas where we believe we hold significant competitive advantages. These areas are typically in geologic basins containing large oil and natural gas resources that can support multiple-year development programs. We usually hold substantial land or mineral interest positions and possess thorough geologic, geophysical, engineering and operational experience and data, often proprietary. We also have favorable access to production, processing and gathering infrastructure, as well as excellent relations with partners, suppliers, other interest holders and host governments. We believe that we've attained this stature in a number of areas that represent the majority of our production. These areas also traditionally yield higher returns on investment, and therefore we've concentrated our activities in them and exited other areas that did not meet these standards.

How concentrated are you in North America?

LIMBACHER: We have a significant, high-performing niche in this business – but *niche* does not mean *small*. North America provides more than 85 percent of our production and reserves. International provides the rest, and although International offers a great deal of near-term growth and meaningful long-term potential, our core business will remain North American natural gas. Considering the market's exceptional strength, we believe that our strategic focus is just right.

How can Burlington succeed longer term, given the maturity of North American natural gas?

SHAPIRO: First, our assets are concentrated in areas in which we've demonstrated the ability to find new inventory. And second, although North American natural gas is a mature business, it's also a high-return business. We believe that by focusing on margins and developing differential expertise through our *Basin Excellence* approach, we can capitalize on opportunities and access new supplies more efficiently than the competition, and thus continue to grow.

Are your core properties in North America performing as expected?

LIMBACHER: Yes. With an aggregate annual base production decline rate of less than 20 percent, which is low relative to that of our North American peers, we don't have to invest as much capital to maintain production. This, and an efficient capital program, enabled us to achieve 10 percent volume growth in 2003, if adjusted for the prior year's property sales, with increases from Canada, South Louisiana, the Williston Basin and the Barnett Shale. In addition, our large opportunity portfolio enables a fungible investment approach in which we can shift capital among basins in response to opportunities. Our core properties are extremely important, and we work diligently to capitalize on the opportunities they offer and to upgrade them through acquisitions.

"We believe that by focusing on margins and developing differential expertise through our *Basin Excellence* approach, we can identify opportunities and access new supplies more efficiently than the competition."

Where do you expect your 2004 volume growth to come from?

LIMBACHER: We expect production growth during 2004 near the upper end of our 3 percent to 8 percent average annual target range, a very significant achievement, given our large size. Furthermore, we expect this growth to stem from exploration and production capital investments of only $1.5 billion that should be fully funded by internally generated cash flow. This is a tribute to the quality of our North American assets. We anticipate growth from the U.S.; a full year of production from Algeria; and increases from offshore China, Ecuador and the East Irish Sea.

Can this growth continue beyond 2004?

LIMBACHER: Yes, and we are working to ensure sustainable growth for the rest of the decade through a variety of initiatives. Among them are Burlington's substantial North American drilling inventory, possible follow-on phases in several of our International programs, and a highly active unconventional resources exploration program that could contribute a greater share of future production. We also expect entirely new opportunities to emerge in the future.

What role will exploration play in your growth?

LIMBACHER: By design, our exploration focuses primarily on our core North American positions. For example, in Canada, concentric exploration is extending existing trends, sometimes by miles at a time. We're reviving our legacy holdings in South Louisiana and stepping up our unconventional resources exploration throughout North America. Internationally, we're focusing in areas that we hope will become core holdings.

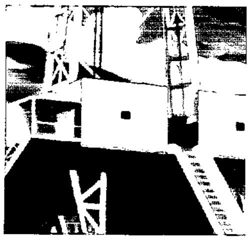
Other companies are exiting the Western Canadian Sedimentary Basin. How can Burlington succeed there?

ELLIS: What differentiates Burlington from the others is the high quality of our assets and our focus on costs. Our properties are highly concentrated in what we believe are resource-rich areas that offer significant drilling inventories and opportunities for production growth. Our capital and expense management programs have produced industry-leading results. Combined, these allow us to grow profitably in a competitive environment.

What are your growth prospects in Canada?

ELLIS: We expect modest production growth in 2004, as we moderate spending during a time of high industry activity and volatile currency exchange rates. We have identified opportunities to extend the boundaries of our *Basin Excellence* areas and are building inventory throughout our core assets. The Canadian division is poised to exploit this inventory at the pace required by Burlington's

OUR ASSETS EXCEL



"Our substantial drilling portfolio enables a fungible investment approach in which we can shift capital among basins in response to opportunities."

capital allocation decisions over the next five years.

Is Canada's Deep Basin living up to expectations?

ELLIS: Absolutely. Annual production rose 12 percent during 2003, to a record 327 MMCFED. We maintain about 1,200 potential drilling locations and recently obtained a prime acreage position in the new Brassey trend on the basin's western edge that will expand that inventory. The Deep Basin is solidifying its position as another legacy asset for Burlington.

What other areas show promise?

ELLIS: We have substantial inventory in the resource-rich Lower Cretaceous rocks that underlie our position in the Western Canadian Sedimentary Basin. All of our asset teams are keenly focused on identifying and exploiting opportunities throughout our asset portfolio. We expect Canada to serve as a mainstay of Burlington's North American natural gas production for years to come.

The Madden Field in Wyoming is a significant producer. Is there any additional potential?

WINSTEAD: A very active program is under way in the Lower Fort Union zone, a shallow formation considered fully developed just a year ago. But knowing that more projects would become economical if costs could be lowered, our personnel redesigned their drilling and completion programs, cutting costs by 55 percent. This made possible 43 new wells and an inventory of additional opportunities. We are also drilling a deep exploratory well to test the Frontier formation.

How are the Williston Basin waterfloods progressing?

WINSTEAD: Results are exceeding expectations. Our Cedar Hills and East Lookout Butte programs are probably two of the world's largest horizontal waterfloods, and their production response has been extremely strong. We successfully tested 160-acre infill drilling spacing during 2003, and will continue this program during 2004. We exited the year with record net production of 12,500 BOD, up 45 percent from 2002, and expect production to more than double within the next few years.

Can you achieve further growth in the Barnett Shale?

WINSTEAD: Yes. Production is growing faster than anticipated as a result of accelerated drilling, with 163 new wells in 2003. We tied in 145 wells, and currently estimate that up to 400 more wells are feasible, depending on spacing. We produced 65 MMCFED net at year-end, up 185 percent, and cut average well costs about 15 percent. We also initiated horizontal drilling to evaluate the technology for wider use.

Does South Louisiana offer any remaining potential?

WINSTEAD: It does. Net production climbed 27 percent in 2003, peaking at 155 MMCFED at midyear after we revived several older fields with new drilling and recompletions. Then, in early 2004 we acquired new or additional interests in eight properties that we believe contain development potential. We will begin drilling on them shortly. Also, we continue exploiting our legacy fee land holdings of 660,000 acres.

The San Juan Basin just keeps getting better. What makes it unique?

FRALEY: This great legacy asset provides nearly 30 percent of Burlington's production while consuming less than $150 million in capital each year – just 10 percent of the company's current budget. As for the future, our basin studies confirm that thousands of additional wells are needed to develop the remaining natural gas. We are the largest producer there, with a drilling inventory that offers years of opportunity. Also, despite the basin's maturity, we've stabilized production, halting the declines experienced a few years ago. This means the San Juan can continue serving as one of the primary sources of Burlington's strong cash flow.

What is the San Juan Basin's cost performance?

FRALEY: This is a classic example of *Basin Excellence.* We're driving down costs despite service cost inflation. From 2001 through 2003, we cut expenditures for drilling by 10 percent, for well completions by 18 percent and for workovers by 17 percent. Meanwhile, lease-operating costs remain flat. We've pursued continuous process improvement, bundled some of our needs with other divisions, contracted for rigs a year at a time and conducted rigorous peer comparisons. Many such small steps add up to major savings.

Does rising opposition to drilling in the West threaten your operations in the San Juan Basin?

FRALEY: We believe that our drilling and development program will not be significantly impacted. However, the greater scrutiny that producers face here makes it essential that we meet the most stringent environmental standards. We devote a great deal of focus on complying with regulations, and have compiled an excellent record. We'll continue working to educate the public about the industry's sound environmental performance and positive contributions to the communities in which we live and work.

Some people believe Burlington should step up its international efforts. How do you respond?

LIMBACHER: The role of International is to profitably provide opportunities for larger-scale additions to reserves and production, but as an *enhancement to,* not a *substitute for,* our North American natural gas business. Our measured, low-risk approach is working, as our rising international production shows.

SHAPIRO: We don't disagree with critics who say that a larger international program might deliver higher growth. But experience shows that heavy international involvement also carries risks of delays, economic upheavals and geopolitical uncertainty, all of which can lead to subpar returns. Consequently, we like our current level of international exposure and don't feel compelled to chase more exposure just to try to achieve higher growth. We "learn first and spend second" and strive to leverage our core skills into new areas.

"We use our proven abilities in recovering geologically challenging resources to enter new areas that contain previously bypassed potential."

Have you established international core areas?

NUSZ: We are currently in a several-year process of evaluating and testing a half-dozen potential core areas in Northwest Europe, North Africa, Latin America and China. We already have production in all of them, and we're now assessing whether we can build sustainability through the *Basin Excellence* attributes we so clearly demonstrate in North America. We've achieved this level in Northwest Europe, and within a few years expect to have meaningful positions in three to four core areas.

How quickly is production ramping up at your major international projects?

NUSZ: At year-end, the MLN Field in Algeria was producing about 13,000 BOD net. In China, the Bootes and

OUR ASSETS EXCEL

Ursa Fields were producing 13,000 BOD net, and actually approached 15,000 BOD net in early 2004. In the East Irish Sea, the Rivers Fields should begin production during the first half of 2004 and plateau at 100 MMCFED net. We also expect the new Yuralpa Field in Ecuador to yield 6,000 BOD net later in the year.

What are your unconventional resource initiatives?

LIMBACHER: We use our proven abilities in recovering geologically challenging resources to enter new areas that contain previously bypassed potential. Successful examples include the San Juan Basin coalbed methane program, the Barnett Shale program and numerous tight sands trends in the U.S. and Canada. We continually evaluate a number of possible programs, but since these are high-risk in nature, we limit our up-front exposure and devise low-cost exit strategies. Past results suggest that several of these initiatives could prove productive over the longer term.

What do you expect natural gas prices to do in the near and long term?

SHAPIRO: Our focus is not on predicting prices, but on operating as efficiently as possible in order to earn sector-leading returns regardless of the price levels. We share the prevailing view that prices will remain volatile, likely at higher average levels than in the past. But we will not assume a continuation of the current price strength until we learn more about its sustainability.

Are your natural gas realizations still impacted by wide basis differentials in the West?

SHAPIRO: The situation improved dramatically in 2003 with the major expansion of an industry pipeline in the northern Rocky Mountains, and the federally mandated reallocation of volumes on a pipeline serving the San Juan Basin. These helped narrow natural gas price differentials between these areas and prime markets such as Louisiana's Henry Hub. Meanwhile, the industry's declining production in Western Canada, together with strong market demand, have boosted natural gas price realizations there.

How does Burlington withstand commodity price volatility?

SHAPIRO: We're accustomed to the inevitable market cycles. Rather than alter our plans whenever prices change, we've structured Burlington with the intent of operating profitably in any likely price environment. Our multiyear drilling programs continue with little change, thereby maximizing efficiency, as we also watch costs. Regardless of the price levels, we strive to perform differentially to our peers while earning returns that healthily exceed our cost of capital. Meanwhile, we use market volatility to create opportunities for hedging and acquisitions.

What is Burlington's hedging philosophy?

SHAPIRO: We believe in hedges, but take an opportunistic approach rather than defensively hedging to protect the balance sheet. Hedges help lock in favorable prices on a portion of our production during market peaks, thus ensuring at least minimal returns if prices fall. On the other hand, by utilizing wide price collars we still participate in the gains, should prices rise instead. We do not take large single positions, nor do we hedge more than half of our production, nor for more than a few years into the future.

"The greatest positive impact on Burlington during 2004 should come through the meaningful growth in production we expect from our current assets."

Can you continue holding costs flat?

LIMBACHER: Our goal is to maintain finding and development costs that are 10 percent to 15 percent lower than the competition, year in and year out, despite industry cost inflation pressures. We offset these pressures with our high-quality asset base, program drilling approach, and increasingly effective global purchasing initiatives. This effort is a key to achieving our goal of generating sector-leading returns.

SHAPIRO: Staying low cost is essential because we have no influence over the commodity price cycles and their ongoing volatility. But by driving down our costs, we believe Burlington can remain profitable in any likely price environment.

How has Burlington approached acquisitions in this environment?

SHAPIRO: We've had significant recent success, spending $228 million in 2003 on a half-dozen transactions that added 228 BCFE in reserves at just $1 per MCFE. All were bolt-on acquisitions that expanded our presence in such core areas as the Barnett Shale trend in North Texas, the San Juan Basin, Canada's Whitecourt/O'Chiese area and the Dutch North Sea. In early 2004 we also made an acquisition in South Louisiana. We're always interested in more bolt-on transactions.

Would you like to make larger acquisitions?

SHAPIRO: We believe that further consolidation in our industry is inevitable, and we expect to be a consolidator. The key is not just doing deals to buy growth but exercising discipline. When commodity prices are high, asking prices of properties tend to rise. We wait for the right time in the price cycle to avoid embedding high costs on our balance sheet. Also we are highly selective. Many properties on the market currently simply don't fit our strategies. We believe that better opportunities could become available during later market downturns.

How will you invest your planned $1.5 billion in capital during 2004?

LIMBACHER: About 85 percent of our exploration and production capital will go to North America, primarily for gas development in the Rocky Mountain fairway in the U.S. and Canada, the majority for low-risk development and exploitation programs. The rest will go to International operations, a decline from 2003 since most of our major development projects are nearing completion.

What do you intend to do with that $757 million in cash on your balance sheet?

SHAPIRO: For now, we intend to hold on to it and evaluate opportunities as they come along. The traditional uses for cash are to fund drilling programs, make share repurchases, increase the cash dividend, pursue acquisitions or pay down debt. All of these options are attractive under the right circumstances.

What do you believe will have the greatest positive impact on Burlington during 2004?

LIMBACHER: We believe that by delivering on our 2004 production targets and the major project start-ups, we will continue to build the market's confidence in our ability to generate further growth in 2005 and beyond.

SHAPIRO: Continued differential performance, demonstrated through achieving production growth while generating sector-leading returns, will be key to earning greater recognition from the marketplace.

"Our focus is not on predicting prices, but on operating as efficiently as possible in order to earn sector-leading returns regardless of what prices do."

OUR PEOPLE EXCEED

Burlington Resources' achievements stem from the contributions of our workforce of more than 2,100 employees, who continue to exceed expectations as the company enhances its organizational effectiveness.

OUR PEOPLE EXCEED

To discuss the role that Burlington Resources' people play in our success, we call upon a panel of our company's leaders:

John Williams, Sr. VP, Exploration

Rick Diaz, VP and Chief Information Officer

Byrd Larberg, VP and Chief Geologist

Joe McCoy, VP, Controller and Chief Accounting Officer

Brent Smolik, VP and Chief Engineer

Bill Usher, VP, Human Resources

What role does geoscience play in Burlington's *Basin Excellence* approach?

LARBERG: Understanding the geological and geophysical basis for crude oil and natural gas formation and migration, as well as for the reservoir trapping and sealing mechanism, provides the underlying foundation of our *Basin Excellence* concepts. It is also a key to improving our drilling success rates and lowering finding and developing costs, which are essential to *Basin Excellence*. We now find that our explorationists perform twice as much geological and geophysical analytical work today than a few years ago, thanks to our recent modernization and standardization of the software suites that manage the digital work flow. We also continually monitor emerging computational technologies that might offer further benefits.

Last year you announced a new exploration structure. How is it working?

WILLIAMS: We combined our four formerly separate division exploration staffs into a Conventional Resources Exploration group and an Unconventional Resources Exploration group, both centralized in Houston. Early indications are that this further reduced the already-low risk profile of our opportunity portfolio. We believe that the centralized teams do a better job of capital allocation, which helped us step up our exploratory drilling last year and generate higher overall success rates.

How are you facilitating technical knowledge exchange?

SMOLIK: We've supplemented traditional training by starting in-house conferences on specific topics, such as tight gas stimulation techniques, and for specific job disciplines, such as facility and drilling engineers, geologists and geophysicists, project managers and others. Our people discuss geoscience and engineering challenges they've overcome and how to apply lessons learned. This has helped us lower our cost structure, provide greater visibility to internal experts, and better avoid repeating prior mistakes. We've also benefited from the broad implementation of the *People Skills* database, which helps identify the technical expertise available within the company.

How do the back-office and information technology functions contribute to success?

McCOY: The manner in which we conduct our financial and administrative functions enhances operational decision making by providing our staffs with timely, accurate and meaningful information. We also reinforce Burlington's cost-conscious culture by pursuing efficiency in our back-office functions. We believe that we can support the company's growth in our established basins without adding back-office staff, thus helping us achieve cost excellence.

DIAZ: We use information technology to lower the cost of business processes and integrate the data flow throughout the company. This shortens cycle times and improves productivity and flexibility. For example, we added seismic interpretation software to help our technical staffs better plan wells in the MLN Field. Other software improved the San Juan Basin's geologic mapping, contributing to reserve increases there. A number of new applications improve the flow of information between departments, again enhancing our decision making.

professional development and training, and emphasize succession planning and organizational staff planning at all levels. Our workforce is highly stable, and we fill the few openings that become available with both recent college graduates and highly experienced personnel.

Does Burlington's workforce participate in an incentive program?

USHER: Three years ago we implemented a comprehensive incentive program called Alignment to Value, or ATV. Every Burlington employee has individual goals that in turn support our divisional and company objectives. Burlington's overall ATV targets include specific metrics for return on capital employed, per-share growth in production and appraised net worth, reserve replacement costs and unit operating costs. We then

"We evaluate and reward employees based on attainment of individual and company goals, as well as on shareholder returns and safety performance."

evaluate and reward employees based on attainment of these company goals, as well as on the vital measures of shareholder returns and safety performance.

Are you realizing synergies between the U.S. and Canadian staffs?

USHER: Yes, substantial knowledge exchange is occurring in the exploration, production, financial and information systems arenas. We have also transferred a handful of key personnel between the two countries. The resulting synergies are increasingly important, given Canada's growing tight sands development programs and possible coalbed methane programs. Both are Burlington specialties in the U.S., and we have found that our Canadian staff has also developed substantial operational expertise.

How are you addressing the aging industry workforce?

USHER: At Burlington, *aging* translates into *more experienced.* Rather than worry about employees' ages, we focus on maintaining their capability levels. We provide professional development and training, and emphasize succession planning and organizational staff planning at all levels.

How is Burlington controlling benefits cost inflation?

USHER: Rising benefits costs, particularly for medical coverage, are a challenge for every company. We regularly review our programs to ensure their competitiveness, and consider alternatives with the goal of achieving optimum value for employees versus expense. We share benefits costs with employees, and enable those in the U.S. to select the coverages that best meet their individual needs. Last, we regularly inform employees on how to take advantage of negotiated medical care discounts. We believe that these steps have prevented much of the inflation in benefits costs that would have otherwise occurred.

OUR COMMUNITY ENERGIZES

At Burlington Resources, we accept the responsibility of serving as good corporate citizens. This commitment entails compliance with the highest ethical standards. It also involves responding to civic concerns through both the Burlington Resources Foundation and personal efforts that help energize our communities.

OUR COMMUNITY ENERGIZES

To discuss the manner in which we meet our corporate social responsibilities, we call upon a panel of Burlington Resources' leaders:

Dave Hanower, Sr. VP, Law and Administration

Joe McCoy, VP, Controller and Chief Accounting Officer

Rick Plaeger, VP and General Counsel

Gavin Smith, VP, Corporate Affairs

How does Burlington address rising public concern about corporate governance?

PLAEGER: Integrity has long been a core Burlington value. We place great emphasis on operating in accordance with high ethical standards and in compliance with the law. These values and our commitment to a strong governance structure are reflected in comprehensive codes of business conduct and ethics, and in written board governance guidelines and committee charters that were in place even before they were required by the Sarbanes-Oxley Act. The code, guidelines and board committee charters are available to investors and the public on our Internet site.

What is the role of the board of directors in ensuring compliance?

McCOY: The board's audit committee provides further oversight of the work that is initially performed by our financial staffs, and then audited by an independent accounting firm.

PLAEGER: The board also reviews the company's strategic plans and operational results to ensure that we are working in the best interests of shareholders, while serving as a good corporate citizen. Our board members were carefully selected to offer an optimal blend of diverse managerial, financial and professional expertise, as well as experience relevant to our business. The criteria for selecting board candidates, and their general responsibilities, are further described in our Corporate Governance Guidelines.

Has the Sarbanes-Oxley Act forced changes in your financial controls?

McCOY: We have always felt that the internal controls traditionally embedded in our financial reporting process were critically important. While the Sarbanes-Oxley Act requires greater documentation and testing of our control systems, this gives us the opportunity to further refine and enhance the effectiveness of our reporting processes. We are finding that this effort is a value-adding proposition.

Are you concerned about Burlington's ability to operate in places where there is antidevelopment sentiment?

HANOWER: We seek out areas that offer significant hydrocarbon potential as well as a desire for development on the part of local inhabitants. In the few areas where we've faced opposition in the past, we've successfully addressed the concerns and won agreement to proceed. If we found that a majority remained opposed to our entry into a new area, we would reconsider our plans.

Do you have an indigenous peoples' rights policy?
HANOWER: Yes. We adopted a policy in early 2004 and published it on our Internet site. It's also important to point out that virtually all the concerns traditionally addressed in such policies were already covered by long-standing Burlington practices.

How much were Burlington's charitable contributions in 2003?
SMITH: The Burlington Resources Foundation contributed a record $6.2 million in 2003, up nearly one-third from $4.7 million the year before.

How much did Burlington employees contribute?
SMITH: During 2003, the foundation provided just over $1 million in matching funds for charitable donations made by employees. We match donations for higher education on a two-for-one basis, and during 2003 began matching other eligible donations dollar-for-dollar while lowering the minimum level for matching to $50. In addition to their own funds, our employees volunteered thousands of hours of their personal time to philanthropic activities.

What do shareholders gain from your community involvement?
SMITH: We believe that a healthier community builds happier, more productive employees. Our involvement also conveys in a visible manner that we meet our civic responsibilities. This enhances our credibility whenever we interact with the larger community.

Why make charitable investments at all?
SMITH: The public expects more of business than our traditional functions of producing useful products, jobs and tax revenue. It recognizes that we are a repository of expertise. Thus, we are expected to help address societal needs by applying our skills along with a portion of our profits. At Burlington we accept this expanded role, and we believe in improving the well-being of the communities in which our employees live and work.

What were the major areas of investment?
SMITH: The three leading areas, each with about a quarter of our total contributions, were human services, educational institutions and medical care initiatives. These were followed by donations to civic, cultural and youth services initiatives.

What were other highlights from the year?
SMITH: We increased donations in Canada, reflecting our rising presence there, and were honored for our community involvement by the Calgary city and Alberta provincial governments. The San Juan Division earned a prestigious local award that was partly based on community service. We made key donations to children's hospitals in several cities. A donation to a hospital in Algeria dramatically improved care for kidney patients. We inspired employee volunteerism by supporting Habitat for Humanity's *More than Houses – Building Communities* campaign, in which employees build five homes each year for the less fortunate in Houston, Midland, Fort Worth and Canada. In Houston, we were a major sponsor of Habitat's SuperBUILD program, which constructed 38 homes in the days preceding SuperBowl XXXVIII. There are hundreds of such examples, each highly important to our employees and the communities in which they live. We are very gratified that we can assist through both contributions and our volunteer efforts.

"We help address societal needs by applying our skills, along with a portion of our profits.The foundation contributed a record $6.2 million in 2003, up nearly one-third from $4.7 million the year before."

The Burlington Resources Board of Directors.
At top, from left, Barbara Alexander,* William Wade, John LaMacchia, Kenneth Orce, Robert Harding, Walter Scott, Donald Roberts, Randy Limbacher* and James Runde.*
At bottom, from left, John Schwarz, Reuben Anderson, Bobby Shackouls, Laird Grant, James McDonald and Steven Shapiro.*

* Elected in January 2004

BOARD OF DIRECTORS

Ms. Barbara T. Alexander
Independent Consultant
and Former Senior Advisor
UBS Warburg LLC

Mr. Reuben V. Anderson (1)(3)
Partner
Phelps Dunbar LLP

Ms. Laird I. Grant (1)
Managing Director
U.S. Trust Company
and Chief Investment Officer
U.S. Trust Company of Florida

Mr. Robert J. Harding (1)(3)
Chairman
Brascan Corporation

Mr. John T. LaMacchia (2)
Chairman and Chief Executive Officer
Tellme Networks, Inc.

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

Mr. James F. McDonald (2)(3)
Chairman, President
and Chief Executive Officer
Scientific-Atlanta, Inc.

Mr. Kenneth W. Orce (3)
Senior Partner
Cahill Gordon & Reindel

Mr. Donald M. Roberts (1)
Retired Vice Chairman and Treasurer
United States Trust Company of New York
and U.S. Trust Corporation

Mr. James A. Runde
Special Advisor
and Former Vice Chairman
Morgan Stanley & Co. Incorporated

Mr. John F. Schwarz (2)
Chairman, President
and Chief Executive Officer
Entech Enterprises, Inc.

Mr. Walter Scott Jr. (2)(3)
Chairman
Level 3 Communications, Inc.

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

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

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

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

CORPORATE INFORMATION

Principal Corporate Office
Burlington Resources Inc.
717 Texas Avenue, Suite 2100
Houston, Texas 77002
(713) 624-9500
www.br-inc.com

Annual Meeting
The Annual Meeting of Stockholders
will be in Houston, Texas, on April 21, 2004.

Common Stock Listings
New York Stock Exchange
Symbol: BR
Toronto Stock Exchange
Symbol: B

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

OFFICERS

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

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

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

Mr. L. David Hanower
Senior Vice President,
Law and Administration

Mr. John A. Williams
Senior Vice President, Exploration

Ms. Ellen R. DeSanctis
Vice President, Investor Relations
and Corporate Communications

Mr. M. Richard Diaz
Vice President
and Chief Information Officer

Mr. Mark E. Ellis
President
Burlington Resources Canada Ltd.

Mr. Richard E. Fraley
Vice President, San Juan Division

Mr. Daniel D. Hawk
Vice President and Treasurer

Mr. C. Scott Kirk
Vice President, Marketing

Mr. G. M. Byrd Larberg
Vice President and Chief Geologist

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

Mr. Thomas B. Nusz
Vice President, International Division

Mr. Frederick J. Plaeger II
Vice President and General Counsel

Mr. Gavin H. Smith
Vice President, Corporate Affairs

Mr. Brent J. Smolik
Vice President and Chief Engineer

Mr. William B. Usher
Vice President, Human Resources
and Administration

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

Mr. Barry J. Winstead
Vice President, Mid-Continent Division

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.

RECONCILATION OF GAAP* TO NON-GAAP MEASURES

***Generally Accepted Accounting Principles**

($ in Millions)

Net cash provided by operating activities to discretionary cash flow

	Full Year	
	2003	2002
Net cash provided by operating activities	$2,539	$1,549
Adjustments:		
Working capital	83	(45)
Changes in other assets & liabilities	(22)	34
Discretionary cash flow	$2,600	$1,538

Return on capital employed (ROCE)

Net Income - 2003	$1,201
Add: interest expense after tax	209
Earnings before after-tax interest expense	$1,410

	Dec. 31, 2003	Dec. 31, 2002
Total debt (GAAP)	$3,873	$3,916
Less: cash & cash equivalents	757	443
Net debt (non-GAAP)	3,116	3,473
Stockholders' equity	5,521	3,832
Total adjusted capital	8,637	7,305
Plus: cash & cash equivalents	757	443
Total capital	$9,394	$7,748
ROCE (GAAP)	16.5%	
Impact of cash and cash equivalents	1.2%	
ROCE (non-GAAP)	17.7%	

Total debt to total capital to net debt to total capital

	Dec. 31, 2003
Total debt	$3,873
Stockholders' equity	5,521
Total capital	$9,394
Total debt	$3,873
Adjustment:	
Less: cash & cash equivalents	757
Net debt	$3,116
Net debt	$3,116
Stockholders' equity	5,521
Total adjusted capital	$8,637
Total debt to total capital ratio	41%
Adjustment:	
Less: impact of cash & cash equivalents	5%
Net debt to total capital ratio	36%

CONSISTENT

REASONS

BURLINGTON RESOURCES

BURLINGTON RESOURCES

RESULTS

CONTINUING

CONTINUING

RESULTS

BURLINGTON
RESOURCES

BURLINGTON
RESOURCES

REASONS

CONSISTENT

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) Paragraph omitted pursuant to SEC Release Nos. 33-8238 and 34-47986;

(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 26, 2004

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

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) Paragraph omitted pursuant to SEC Release Nos. 33-8238 and 34-47986;

(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 26, 2004

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

Exhibit Number	Description	
†10.22	Poco Petroleums Ltd. Incentive Stock Option Plan (Form S-8 No. 333-91247, filed November 18, 1999)	*
†10.23	Employee Savings Plan for Eligible Employees of Poco Petroleums Ltd. (Exhibit 4.4 to Form S-8 No. 333-95071, filed January 20, 2000)	*
†10.24	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)	*
†10.25	Burlington Resources Inc. 2000 Stock Option Plan for Non-Employee Directors (Exhibit 10.30 to Form 10-Q, filed August 2000)	*
†10.26	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)	*
†10.27	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)	*
10.28	Canadian Credit Agreement, dated as of March 31, 2000, as Amended and Restated December 4, 2003, among Burlington Resources Canada Ltd., Burlington Resources Canada (Hunter) Ltd., Burlington Resources Inc. and JPMorgan Chase Bank, Toronto Branch	
†10.29	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	
	Amendment No. 2 dated December 2003 to Burlington Resources Inc. 2002 Stock Incentive Plan	
10.30	Burlington Resources Inc. 1997 Employee Stock Incentive Plan	*
	Amendment dated December 2003 to Burlington Resources Inc. 1997 Employee Stock Incentive Plan	
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.

†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 Number	Description	
†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	
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	
†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 10.2 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)	*
10.17	$400 million Short-term Revolving Credit Agreement, dated as of February 25, 1998, as Amended and Restated December 4, 2003, between Burlington Resources Inc. and JPMorgan Chase Bank, as agent	
10.18	$600 million Long-term Revolving Credit Agreement, dated as of February 25, 1998, as Amended and Restated December 7, 2001, between Burlington Resources Inc. and JPMorgan Chase Bank, as agent (Exhibit 10.19 to Form 10-K, filed February 2002)	*
	Amendment No. 1 dated April 25, 2002 to $600 million Long-term Revolving Credit Agreement (Exhibit 10.19 to Amendment No. 1 to Form S-4, filed June 2002)	*
	Amendment No. 2 dated December 5, 2002 to $600 million Long-term Revolving Credit Agreement (Exhibit 10.19 to Form 10-K, filed March 12, 2003)	*
	Amendment No. 3 dated December 4, 2003 to $600 million Long-term Revolving Credit Agreement	
†10.19	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)	*
†10.20	The LL&E Supplemental Excess Plan (Exhibit 10(j) to LL&E's Form 10-K, filed March 1993)	*
†10.21	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)	*

BURLINGTON RESOURCES INC.

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 November 18, 1999 (Exhibit 3.1 to Form 10-K, filed March 17, 2000)	*
	Certificate of Elimination of Burlington Resources Inc. filed December 12, 2002 relating to the elimination of the Special Voting Stock (Exhibit 3.1 to Form 10-K, filed March 12, 2003)	*
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)	*
†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)	*
†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)	*
†10.4	Burlington Resources Inc. Supplemental Benefits Plan as amended and restated (Exhibit 10.5 to Form 10-K, filed February 1997)	*
†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)	*
†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)	*

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 26, 2004
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Director, Executive Vice President and Chief Financial Officer	February 26, 2004
/s/ JOSEPH P. McCOY Joseph P. McCoy	Vice President, Controller and Chief Accounting Officer	February 26, 2004
/s/ BARBARA T. ALEXANDER Barbara T. Alexander	Director	February 26, 2004
/s/ REUBEN V. ANDERSON Reuben V. Anderson	Director	February 26, 2004
/s/ LAIRD I. GRANT Laird I. Grant	Director	February 26, 2004
/s/ ROBERT J. HARDING Robert J. Harding	Director	February 26, 2004
/s/ JOHN T. LaMACCHIA John T. LaMacchia	Director	February 26, 2004
/s/ RANDY L. LIMBACHER Randy L. Limbacher	Director	February 26, 2004
/s/ JAMES F. McDONALD James F. McDonald	Director	February 26, 2004
/s/ KENNETH W. ORCE Kenneth W. Orce	Director	February 26, 2004
/s/ DONALD M. ROBERTS Donald M. Roberts	Director	February 26, 2004
/s/ JAMES A. RUNDE James A. Runde	Director	February 26, 2004
/s/ JOHN F. SCHWARZ John F. Schwarz	Director	February 26, 2004
/s/ WALTER SCOTT, JR. Walter Scott, Jr.	Director	February 26, 2004
/s/ WILLIAM E. WADE, JR. William E. Wade, Jr.	Director	February 26, 2004

PART IV

ITEM FIFTEEN

EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

Reports on Form 8-K

On October 22, 2003, the Company furnished on Form 8-K, pursuant to Item 12, Results of Operations and Financial Condition, and Item 9, Regulation FD Disclosure, a press release announcing its earnings results for the third quarter of fiscal year 2003.

On November 17, 2003, the Company disclosed on Form 8-K, pursuant to Item 5, Other Events, a reduction in the Canadian federal income tax rate for companies in the natural resources sector.

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 AND RELATED SHAREHOLDER MATTERS

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, 2003

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 (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	3,815,390	44.13	6,739,900
Equity compensation plan not approved by security holders (1)	1,659,150	44.63	2,097,709
Total	5,474,540	44.28	8,837,609

(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) In connection with BR's proposed 2-for-1 stock split in the form of a share distribution payable on June 1, 2004 to stockholders of record on May 5, 2004 and subject to stockholder approval of an amendment to BR's Certificate of Incorporation increasing the number of authorized shares of BR's Common Stock from 325 million to 650 million shares, the number of equity securities in the above table shall be adjusted by multiplying each relevant number by 2.

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 "Principal Accountant Fees and Services" in the Proxy Statement and is incorporated herein by reference.

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.

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

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.

	2003	2002	2001
		(In Millions)	
January 1,	$ 10,414	$ 6,000	$ 18,804
Revisions of previous estimates			
Changes in prices and costs	6,050	6,744	(22,602)
Changes in quantities	(111)	(26)	60
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	2,119	1,235	483
Purchases of reserves in place	416	656	1,147
Sales of reserves in place	(86)	(1,215)	(15)
Accretion of discount	1,472	815	2,879
Sales, net of production costs	(3,739)	(2,483)	(2,784)
Net change in income taxes	(2,163)	(2,158)	7,836
Changes in rate of production and other	805	846	192
Net change	4,763	4,414	(12,804)
December 31,	$ 15,177	$10,414	$ 6,000

Quarterly Financial Data—Unaudited

	2003				2002			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In Millions, Except per Share Amounts)							
Revenues	$1,065	$1,059	$1,059	$1,128	$ 830	$ 652	$ 783	$ 703
Income before income taxes and cumulative effect of change in accounting principle(a)	299	396	376	499	234	67	207	61
Income before cumulative effect of change in accounting principle	387	267	278	328	157	79	170	48
Net income(b)	387	267	278	269	157	79	170	48
Basic earnings per common share before cumulative effect of change in accounting principle	1.96	1.34	1.39	1.63	0.78	0.39	0.84	0.24
Net income	1.96	1.34	1.39	1.34	0.78	0.39	0.84	0.24
Diluted earnings per common share before cumulative effect of change in accounting principle	1.95	1.33	1.38	1.62	0.78	0.39	0.84	0.24
Net income(b)	1.95	1.33	1.38	1.33	0.78	0.39	0.84	0.24
Cash dividends declared per common share	0.15	0.15	0.14	0.14	0.14	0.13	0.14	0.14
Common stock price range								
High	57.45	54.07	55.95	48.07	43.67	39.65	45.34	41.60
Low	$46.95	$45.04	$45.83	$40.75	$34.76	$32.00	$36.90	$32.30

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

(b) Fourth quarter 2003 includes a tax benefit of $203 million or $1.03 per diluted share related to the Canadian federal income tax reduction.

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		Other	
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		Other	
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

	North America		Other	
2001	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Future cash inflows	$ 15,544	$ 6,206	$ 3,948	$ 25,698
Less related future				
Production costs	4,612	1,606	1,042	7,260
Development costs	752	654	741	2,147
Income taxes	2,701	1,433	621	4,755
Future net cash flows	7,479	2,513	1,544	11,536
10% annual discount for estimated timing of cash flows	3,971	920	645	5,536
Standardized measure of discounted future net cash flows	$ 3,508	$ 1,593	$ 899	$ 6,000

NGLs (MMBbls)			Natural Gas (BCF)				
North America			North America				Total
U.S.	Canada	Worldwide	U.S.	Canada	Other International	Worldwide	Equivalent (BCFE)
222.2	44.0	266.2	4,884	1,189	729	6,802	10,389
5.8	(12.9)	(7.1)	107	(66)	(35)	6	(102)
9.6	4.8	14.4	253	165	58	476	995
(12.6)	(4.6)	(17.2)	(409)	(158)	(62)	(629)	(871)
2.7	16.4	19.1	59	1,007	207	1,273	1,402
—	—	—	(2)	(1)	—	(3)	(5)
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
177.6	35.5	213.1	3,903	960	251	5,114	7,731
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

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, 2003. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and international interests (excluding Canada and Argentina) and Sproule Associates Limited reviewed the Company's interests in Canada and Argentina. 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		Other	
	U.S.	Canada	International	Worldwide
Proved Developed and Undeveloped Reserves				
December 31, 2000	204.2	57.5	70.0	331.7
Revisions of previous estimates	(10.7)	(0.6)	0.4	(10.9)
Extensions, discoveries and other additions	66.7	2.9	2.5	72.1
Production	(16.1)	(4.3)	(2.7)	(23.1)
Purchases of reserves in place	0.4	1.2	0.8	2.4
Sales of reserves in place	(0.2)	(0.1)	—	(0.3)
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
Proved Developed Reserves				
December 31, 2000	169.7	43.0	10.4	223.1
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

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 fixed-rate depreciation expense, were as follow. Intersegment sales were $17 million and $157 million in 2002 and 2001, respectively. There were no intersegment sales in 2003.

	North America		Other	
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		Other	
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

	North America		Other	
Year Ended December 31, 2001	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Revenues	$2,181	$946	$212	$3,339
Production costs	401	137	17	555
Exploration costs	167	52	39	258
Operating expenses	260	123	45	428
Depreciation, depletion and amortization	438	162	82	682
Impairment of oil and gas properties	184	—	—	184
Income tax provision (benefit)	265	234	(1)	498
Results of operations for oil and gas producing activities	$ 466	$238	$ 30	$ 734

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, 2003	North America U.S.	North America Canada	Other 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	Other 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

Year Ended December 31, 2001	North America U.S.	North America Canada (2)	Other International	Total
		(In Millions)		
Property acquisition				
Proved	$ 67	$1,042	$ 30	$1,139
Unproved (3)	14	876	4	894
Exploration	99	76	48	223
Development				
Proved developed	292	251	10	553
Proved undeveloped	111	37	125	273
Total costs incurred	$583	$2,282	$217	$3,082

The Company estimates that it will spend capital of approximately $440 million, $370 million and $385 million in 2004, 2005 and 2006, respectively, for the development of its proved undeveloped reserves.

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

(2) The amounts exclude deferred taxes of $902 million related to the Hunter acquisition.

(3) The amount for Canada includes $858 million of unproved properties acquired with the Hunter acquisition.

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

By ____________________
Kenneth H. Crowther, P.Eng.
President

KHC:RNJ:db

PERMIT TO PRACTICE
SPROULE ASSOCIATES LIMITED

Signature ____________________

Date Jan 12, 2004

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

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

Our audit does not constitute a complete reserve 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 (except for the Argentine properties, where prices were verified), agreements relating to current and future operations and sales of production, etc. Burlington's Canadian reserve assignments were audited directly by tying into the PEEP reserve database over the Internet, 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 reserve 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 reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The reserve 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 Reserve 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.

Sproule
ASSOCIATES LIMITED

Geological and Petroleum Engineering Consultants

Ref.: 1408.14776

January 12, 2004

Burlington Resources Inc.
Ste. 1400, 5051 Westheimer
Houston, TX 77056-5604

Re: Unqualified Audit Opinion of Burlington Resources Incorporated Canadian and Argentine Proved Reserves, as of December 31, 2003

Gentlemen:

At your request, we have examined the proved oil, natural gas liquids, and natural gas reserve estimates of Burlington Resources Incorporated ("Burlington") Canadian and Argentine properties as of December 31, 2003. Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

Tables 1 and 2 set forth 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 Reserve Estimates Using Net Marketable Gas Volumes

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, MMBbls.	13.2	2.5	15.7
Natural gas, Bcf	1,837	517	2,354
Natural gas liquids, MMBbls	50.9	10.4	61.3

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

Table 2

Summary of Burlington Resources Incorporated Argentine Proved Reserve Estimates Using Net Marketable Gas Volumes

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, condensate and pentanes plus, MMBbls.	0.2	0.7	0.9
Natural gas, Bcf*	45	104	149
Natural gas liquids, MMbbls	0	0	0

* In this table, the gas reserves shown are net marketable volumes after processing shrinkage and fuel losses. The volumes of condensate and pentanes plus have been included with the oil. All volumes are net, after royalties.

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Toll Free: 1-877-777-6135
info@sproule.com, www.sproule.com

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

Over Fifty Years of Service since 1948

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INTERNATIONAL OIL AND GAS CONSULTANTS

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January 14, 2004

Burlington Resources Inc.
5051 Westheimer, Suite 1400
Houston, TX 77056-2125

Re: Proved Reserves as of December 31, 2003

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, 2003. 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	415.6	119.7	535.3
Gas, Billions of Cubic Feet	3,993.5	1,579.4	5,572.9

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 82 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, 2003, and are in accordance with Securities and Exchange Commission guidelines.

REPORT OF INDEPENDENT AUDITORS

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

In our opinion, the accompanying consolidated balance sheet 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, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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.

Additionally, 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 ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." Additionally, as discussed in Note 8 to the consolidated financial statements, on January 1, 2001, the Company changed its method of accounting for its derivative instruments and hedging activities in connection with its adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

February 25, 2004
Houston, Texas

PricewaterhouseCoopers LLP

REPORT OF MANAGEMENT

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

BR maintains a system of internal controls and a program of internal auditing that provides management with reasonable assurance that the Company's assets are protected and that its published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets regularly with BR's independent auditors, financial management, counsel and internal audit. To ensure complete independence, the independent auditors and internal audit personnel have full and free access to the Audit Committee to discuss the results of their audits, the adequacy of internal controls and the quality of financial reporting.

Our independent auditors provide an objective independent review by their audit of the Company's financial statements. Their audit is conducted in accordance with auditing standards generally accepted in the United States of America and includes a review of internal accounting controls to the extent deemed necessary for the purposes of their audit.

Steven J. Shapiro
Executive Vice President and
Chief Financial Officer

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

and gas companies, has included oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves as part of the oil and gas properties, even after SFAS No. 141 and No. 142 became effective.

This interpretation of SFAS No. 141 and No. 142 would only affect the Company's consolidated balance sheet classification of oil and gas leaseholds. The Company's results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*.

At December 31, 2003, the Company had undeveloped and developed leaseholds of approximately $1.3 billion and $2.4 billion that would have been classified on the consolidated balance sheet as intangible undeveloped leaseholds and intangible developed leaseholds, respectively, if it had applied the interpretation currently being discussed. The Company will continue to classify its oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as oil and gas properties until further guidance is provided.

Recent Accounting Pronouncements

On December 23, 2003, the FASB issued SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88, and 106*. This statement revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, *Employers' Accounting for Pensions,* No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,* and No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. The new rules require additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. The new disclosures are effective for 2003 calendar year-end financial statements. The Company has adopted the revised disclosures as of December 31, 2003. See Note 13 of Notes to Consolidated Financial Statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS No. 150). SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. It is to be implemented by reporting the cumulative effect of a change in an accounting principle for financial instruments created before the issuance date of SFAS No. 150 and still existing at the beginning of the interim period of adoption. Restatement is not permitted. The adoption of the provisions of SFAS No. 150 during 2003 did not impact the Company's consolidated financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities* (SFAS No. 149). SFAS No. 149 improves financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. In particular, SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an "underlying" to conform it to language used in FIN No. 45 and amends certain other existing pronouncements. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. In addition, with some exceptions, all provisions of SFAS No. 149 should be applied prospectively. The adoption of SFAS No. 149 did not have a material impact on the Company's consolidated financial position or results of operations.

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,	2003	2002	2001
		(In Millions)	
Income before income taxes and cumulative effect of change in accounting principle for reportable segments	$ 2,032	$ 996	$1,255
Corporate expenses	189	184	170
Interest expense	260	274	190
Other expense (income)—net	13	(31)	(12)
Consolidated income before income taxes and cumulative effect of change in accounting principle	$ 1,570	$ 569	$ 907

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

Year Ended December 31,	2003	2002	2001
		(In Millions)	
Total capital expenditures for reportable segments	$ 1,765	$1,802	$3,434
Corporate administrative capital expenditures	23	35	20
Consolidated capital expenditures	$ 1,788	$1,837	$3,454

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

December 31,	2003	2002	2001
		(In Millions)	
Properties—net for reportable segments	$10,215	$8,402	$8,733
Corporate properties—net	96	101	98
Consolidated properties—net	$10,311	$8,503	$8,831

18. Taxes Other Than Income Taxes

Taxes other than income taxes are as follow.

Year Ended December 31,	2003	2002	2001
		(In Millions)	
Severance taxes	$ 141	$ 85	$ 137
Ad valorem taxes	30	25	17
Payroll taxes and other	16	13	12
Taxes other than income taxes	$ 187	$ 123	$ 166

19. Other Matters

SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Intangible Assets,* were issued in June 2001 and became effective for the Company July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report certain intangibles assets separately from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, and included as intangible assets on the Company's consolidated balance sheets. In addition, the disclosures required by SFAS No. 141 and No. 142 related to intangibles would be included in the notes to the consolidated financial statements. Historically, the Company, like many other oil

17. Segment and Geographic Information

The Company's reportable segments are U.S., Canada and Other International. The Company is engaged principally in the exploration, development, production and marketing of natural gas, crude oil and NGLs. The accounting policies for the segments are the same as those described in Note 1 of Notes to Consolidated Financial Statements. Intersegment sales were $17 million and $157 million in 2002 and 2001, respectively. There were no intersegment sales in 2003.

The following tables present information about reported segment operations.

	North America		Other	
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		Other	
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

	North America		Other	
Year Ended December 31, 2001	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,260	$ 947	$212	$ 3,419
Depreciation, depletion and amortization	459	170	86	715
Impairment of oil and gas properties	184	—	—	184
Income before income taxes and cumulative effect of change in accounting principle	772	458	25	1,255
Properties—net	4,120	3,815	798	8,733
Goodwill	—	782	—	782
Capital expenditures	$ 653	$2,563	$218	$ 3,434

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 $263.6 million in principal, plus interest, punitive damages and attorneys' 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 this matter will be scheduled for trial during 2004. The Company currently does not believe that an unfavorable outcome is probable nor, in the event of an unfavorable outcome, is the Company reasonably able to estimate the possible loss, if any, or range of loss in these lawsuits. Accordingly, there has been no reserve established for this matter.

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.

The Company has established reserves for certain legal proceedings which are 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 with respect to those matters in which reserves have been established of up to approximately $25 million to $30 million in excess of the amounts currently accrued. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued.

While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings 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.

15. Supplemental Cash Flow Information

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

Year Ended December 31,	2003	2002	2001
		(In Millions)	
Interest paid—net of capitalized interest(1)	$ 251	$ 260	$ 155
Income taxes paid—net	$ 171	$ 40	$ 136

(1) Capitalized interest was $25 million, $22 million and $9 million for the years ended December 31, 2003, 2002 and 2001, respectively.

At December 31, 2003, 2002 and 2001, capital expenditures included in Accounts Payable balance on the Consolidated Balance Sheet were $171 million, $290 million and $298 million, respectively.

16. Impairment of Oil and Gas Properties

The Company performs an impairment analysis 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.

As a result of this assessment 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. In December 2001, primarily as a result of the Company's decision to exit the Gulf of Mexico Shelf and divest of certain other properties, the Company recognized a pretax impairment charge of $184 million primarily related to the impairment of oil and gas properties held for sale. These properties were sold during 2002.

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. The cases alleging improper measurement techniques remain pending in MDL-1293.

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 $68 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could also 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. 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. The Company currently does not believe that an unfavorable outcome is probable nor, in the event of an unfavorable outcome, is the Company reasonably able to estimate the possible loss, if any, or range of loss in this lawsuit. Accordingly, there has been no reserve established for this matter.

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 1983 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 provisions of the Act because specific guidance on the accounting for the federal subsidy is pending and, when issued, could require the Company to change previously reported information.

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 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. The Company paid $179 million, $156 million and $128 million of demand charges for the years ended December 31, 2003, 2002 and 2001, 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, 2003 follow.

	(In Millions)
2004	$160
2005	115
2006	110
2007	92
2008	70
Thereafter	386
Total	$933

Lease Obligations

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $38 million, $29 million and $23 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2003 follow.

	(In Millions)
2004	$ 36
2005	29
2006	27
2007	25
2008	26
Thereafter	148
Total	$291

Drilling Rig Commitments

During 1998, the Company entered into agreements to lease two deep water drilling rigs through 2004 with remaining commitments of $22 million. These commitments will be utilized by drilling exploration wells, partner participation or subletting to the extent possible. In addition, the Company has other drilling rig commitments of $5 million and $1 million for 2004 and 2005, 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

Assumptions used to determine net benefit obligations follow.

	Pension Benefits			Postretirement Benefits		
December 31,	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Weighted average assumptions						
Discount rate	6.00%	6.75%	7.25%	6.00%	6.75%	7.25%
Rate of compensation increase	4.50%	4.50%	5.00%	—	—	—

Assumptions used to determine net benefit cost follow.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Weighted average assumptions						
Discount rate	6.75%	7.25%	7.50%	6.75%	7.25%	7.50%
Expected return on plan assets	8.00	8.50	9.00	—	—	—
Rate of compensation increase	4.50%	5.00%	5.00%	—	—	—

The following table provides the target and actual asset allocations in the U.S. pension plan as of December 31,

Asset Category	**Target**	**2003**	**2002**
Equity	65%	68%	64%
Fixed income	35	30	34
Other	—	2	2
Total	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 resulted in the selection of the 8 percent assumption.

A 10 percent annual rate of increase in the per capita cost of pre-age 65 covered health care benefits was assumed for 2004. The rate is assumed to decrease gradually to 5 percent for 2009 and remain at that level thereafter. A 12 percent annual rate of increase in the per capita cost of post-age 65 covered health care benefits was assumed to decrease gradually 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	$ 244	$ (211)
Effect on postretirement benefit obligation	$4,577	$(3,920)

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "Act") was signed into law. Benefit obligations and costs related to prescription drug coverage shown above do not reflect the

The following tables set forth the amounts recognized in the Consolidated Balance Sheet and Statement of Income.

	Pension Benefits		Postretirement Benefits	
Year Ended December 31,	**2003**	**2002**	**2003**	**2002**
	(In Millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$187	$181	$ 42	$ 41
Service cost	9	9	—	—
Interest cost	13	12	3	3
Actuarial loss	24	2	7	1
Currency exchange	4	—	—	—
Participant contributions	—	—	1	2
Benefits paid	(15)	(17)	(7)	(5)
Benefit obligation at end of year	222	187	46	42
Change in plan assets				
Fair value of plan assets at beginning of year	138	155	—	—
Actual return on plan assets	31	(12)	—	—
Currency exchange	4	—	—	—
Employer contribution	22	12	6	3
Participant contributions	—	—	1	2
Benefits paid	(15)	(17)	(7)	(5)
Fair value of plan assets at end of year	180	138	—	—
Funded status	(42)	(49)	(46)	(42)
Unrecognized net actuarial loss	51	48	23	17
Unrecognized prior service cost (benefit)	2	1	(5)	(6)
Net prepaid (accrued) benefit cost	11	—	(28)	(31)
Minimum pension liability	—	(13)	—	—
Intangible asset	—	3	—	—
Accumulated other comprehensive loss	—	10	—	—
Net prepaid (accrued) benefit cost	$ 11	$ —	$ (28)	$ (31)

The accumulated benefit obligation of the U.S. pension plans as of December 31, 2003 and December 31, 2002 was $159 million and $137 million, respectively. The measurement date is December 31. The Company expects to contribute $11 million to its U.S. pension plans in 2004.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
	(In Millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 9	$ 9	$ 9	$—	$—	$—
Interest cost	13	12	11	3	3	3
Expected return on plan assets	(13)	(14)	(14)	—	—	—
Recognized net actuarial loss	4	1	—	—	—	—
Net benefit cost	$ 13	$ 8	$ 6	$ 3	$ 3	$ 3

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 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, 2003, a $7 million liability had been accrued for these benefits and is included in Other Liabilities and Deferred Credits on the Company's Consolidated Balance Sheet.

The Company has a discretionary defined contribution plan (401(k) Plan). 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 $12,000 in 2003. 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 $9 million, $9 million and $8 million to the 401(k) Plan for the years ended December 31, 2003, 2002 and 2001, respectively, to match eligible contributions by employees.

The Company's stock option activity follows.

	Options	Weighted Average Exercise Price
December 31, 2000	6,581,094	$40.08
Granted	1,638,675	50.53
Exercised	(1,052,187)	35.81
Cancelled	(303,324)	47.00
December 31, 2001	6,864,258	42.93
Granted	1,008,850	35.64
Exercised	(404,048)	31.80
Cancelled	(304,846)	45.11
December 31, 2002	7,164,214	42.44
Granted	1,977,890	42.11
Exercised	(3,386,452)	38.88
Cancelled	(281,112)	47.10
December 31, 2003	5,474,540	$44.28

The following table summarizes information related to stock options outstanding and exercisable at December 31, 2003.

Options Outstanding	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price
411,209	$ 23.32–$34.89	$ 31.06	3.1	411,209	$ 31.06
2,860,244	35.38– 44.00	41.28	7.8	1,015,954	39.94
2,203,087	45.25– 52.03	50.65	5.0	1,971,765	50.65
5,474,540	$ 23.32–$52.03	$ 44.28	6.3	3,398,928	$ 45.08

Exercisable stock options and weighted average exercise prices at December 31, 2002 and 2001 follow.

	Options Exercisable	Weighted Average Exercise Price
December 31, 2002	5,530,149	$ 43.22
December 31, 2001	4,838,074	$ 41.41

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 one-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 one-hundredth of a share of Series A Junior Participating Preferred Stock at a price of $200 per one 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

12. Capital Stock

The Company's Common Stock activity follows.

	Number of Shares		
	Issued	Treasury	Outstanding
December 31, 2000	241,188,698	(25,619,893)	215,568,805
Adjustment of unexchanged Poco shares	(10)		(10)
Treasury shares purchased		(16,092,000)	(16,092,000)
Shares issued under compensation plans, net of forfeitures		264,011	264,011
Option exercises		1,052,187	1,052,187
December 31, 2001	241,188,688	(40,395,695)	200,792,993
Shares issued under compensation plans, net of forfeitures		242,216	242,216
Option exercises		404,048	404,048
December 31, 2002	241,188,688	(39,749,431)	201,439,257
Treasury shares purchased		(7,414,990)	(7,414,990)
Shares issued under compensation plans, net of forfeitures		238,084	238,084
Option exercises		3,386,452	3,386,452
December 31, 2003	241,188,688	(43,539,885)	197,648,803

Stock Compensation Plans

The Company's 2002 Stock Incentive Plan (the 2002 Plan) succeeds its 1993 Stock Incentive Plan (the 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 7,500,000. At December 31, 2003, 6,574,900 shares were available for grant under the 2002 Plan.

In 1997, the Company adopted the 1997 Employee Stock Incentive Plan (the 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 5,000,000 shares. At December 31, 2003, 2,097,709 shares were available for grant under the 1997 Plan, of which up to 150,000 shares annually may be restricted stock.

The Company issued 289,425, 257,025 and 256,700 shares of restricted stock in 2003, 2002 and 2001, 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, 2003, 2002, and 2001 was approximately $42.08, $35.73 and $50.30, respectively. Related compensation expense of approximately $11 million, $9 million and $7 million was recognized for the years ended December 31, 2003, 2002 and 2001, respectively.

The Company's 2000 Stock Option Plan (the 2000 Plan) for Non-Employee Directors provides for the annual grant of a nonqualified option for 2,000 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 5,000 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 250,000. At December 31, 2003, 165,000 shares were available for grant under the 2000 Plan.

The following table reflects the changes of the asset retirement obligations during the current year.

	(In Millions)
Carrying amount of asset retirement obligations as of January 1, 2003	$297
Liabilities incurred during the period	102
Liabilities settled during the period	(11)
Current year accretion expense	21
Revisions in estimated cash flows	33
Carrying amount of asset retirement obligations as of December 31, 2003	$442

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 prior periods.

Year Ended December 31,	**2002**	**2001**
	(In Millions, Except per Share Amounts)	
Net income —as reported	$ 454	$ 561
Less: pro forma amounts assuming SFAS No. 143 was applied retroactively (unaudited)	9	16
Net income —pro forma (unaudited)	$ 445	$ 545
Basic earnings per share—as reported	$2.26	$2.71
Basic earnings per share—pro forma (unaudited)	2.21	2.63
Diluted earnings per share—as reported	2.25	2.70
Diluted earnings per share—pro forma (unaudited)	$2.21	$2.62

11. Significant Concentrations

In 2003, 2002 and 2001, approximately 49 percent, 43 percent and 42 percent, respectively, of the Company's natural gas production was transported to direct sale customers through pipeline systems owned by two companies. 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.

Substantially all of the Company's accounts receivable at December 31, 2003 and 2002 result from sales of natural gas, NGLs and crude oil as well as joint interest billings to third party companies. 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.

In December 2003, the Company retired Canadian $100 million (U.S. $75 million) of 6.40% Notes. The Company has debt maturities of $500 million due in 2006, $466 million due in 2007 and $2,950 million due in 2010 and thereafter. The fair value of debt outstanding as of December 31, 2003 and 2002 was $4,483 million and $4,443 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 credit commitments in the form of revolving credit facilities (Revolvers) as of December 31, 2003. The Revolvers are comprised of agreements for $600 million, $400 million and Canadian $390 million (U.S. $300 million). The $600 million Revolver expires in December 2006 and the $400 million and Canadian $390 million Revolvers expire in December 2004 unless renewed by mutual consent. The Company has the option to convert any remaining balances on the $400 million and Canadian $390 million Revolvers to one year and five-year plus one day term notes, respectively. The Revolvers are available to cover debt due within one year. Therefore, commercial paper, if any, credit facility notes and fixed-rate debt due within one year are generally classified as long-term debt. At December 31, 2003, there are no amounts outstanding under the Revolvers and no outstanding commercial paper.

At the Company's option, interest on borrowings under the $600 million and $400 million Revolvers is based on the prime rate or Eurodollar rates. The other Revolver bears interest at rates based on prime or Eurodollar rates also at the Company's option, however, the lenders have the option to provide bankers' acceptances in lieu of Eurodollar rate loans. Under the covenants of the Revolvers, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements).

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 $148 million and $138 million as of December 31, 2003 and 2002, 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 should be allocated to expense using a systematic and rational method. 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 provisions of SFAS No. 143. There was no impact on the Company's cash flows as a result of adopting SFAS No. 143. The pro forma asset retirement obligations would have been $376 million at January 1, 2002 and $297 million at December 31, 2002 had the Company adopted SFAS No. 143 on January 1, 2002. The asset retirement obligations, which are included in the Consolidated Balance Sheet in Other Liabilities and Deferred Credits, were $442 million and $106 million at December 31, 2003 and 2002, respectively. Accretion expense for 2003 was $21 million and is included in Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Income.

hedge derivatives liabilities of $582 million ($361 million after tax), fair value hedge derivative assets of $16 million ($10 million after tax), related liability adjustments to book value of fair-value hedged items of $16 million ($10 million after tax) and an after tax non-cash gain of $3 million was recorded in current earnings as a cumulative effect of accounting change.

Changes in other comprehensive income for the three years ended December 31, 2003 follow.

	(In Millions)
Cumulative effect of change in accounting principle—January 1, 2001	$ (366)
Reclassification adjustments for settled contracts	200
Current period changes in fair value of settled contracts	153
Changes in fair value of outstanding hedging positions	67
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)

Based on commodity prices and foreign exchange rates as of December 31, 2003, the Company expects to reclassify losses of $26 million ($16 million after tax) to earnings from the balance in Accumulated Other Comprehensive Loss during the next twelve months. At December 31, 2003, the Company had derivative assets of $10 million and derivative liabilities of $50 million of which $7 million, $3 million and $33 million is included in Other Current Assets, Other Assets and Other Current Liabilities, respectively, on the Consolidated Balance Sheet.

9. Long-term Debt

Long-term debt follows.

December 31,	**2003**	**2002**
	(In Millions)	
Notes, 6.40%, due 2003(1)	$ —	$ 63
Notes, 5.60%, due 2006	500	500
Notes, 6.60%, due 2007(1)	116	94
Notes, 5.70%, due 2007	350	350
Debentures, $9\frac{7}{8}$%, 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, $7\frac{5}{8}$%, due 2013	100	100
Debentures, $9\frac{1}{8}$%, due 2021	150	150
Debentures, 7.65%, due 2023	88	88
Debentures, 8.20%, due 2025	150	150
Debentures, $6\frac{7}{8}$%, due 2026	67	67
Debentures, $7\frac{3}{8}$%, due 2029	92	92
Notes, 7.20%, due 2031	575	575
Notes, 7.40%, due 2031	500	500
Discounts and Other	(43)	(41)
Total debt	3,873	3,916
Less current maturities	—	63
Total long-term debt	$3,873	$3,853

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

As of December 31, 2003, the Company had the following commodity related derivative instruments outstanding with average underlying prices that represent hedged prices of commodities at various market locations.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Average Underlying Prices	Fair Value Asset (Liability) (In Millions)
2004	Swap	Cash flow	18,050,390		$ 3.59	$(22)
	Purchased put	Cash flow	73,681,845		4.35	12
	Purchased put	Not designated	11,351,257		3.16	—
	Written call	Cash flow	73,681,845		6.47	(15)
	Written put	Not designated	11,351,257		3.16	—
	Purchased put	Cash flow		2,275,000	26.60	1
	Purchased put	Not designated		455,000	20.00	—
	Written call	Cash flow		2,275,000	33.40	(3)
	Written put	Not designated		455,000	20.00	—
	Swap	Fair value	2,641,800		3.18	5
	N/A	Fair value (obligation)	2,641,800		3.21	(4)
2005	Swap	Cash flow	10,511,522		3.20	(12)
	Swap	Fair value	1,579,200		2.82	2
	N/A	Fair value (obligation)	1,579,200		2.83	(2)
2006	Swap	Cash flow	912,000		3.06	(1)
2007	Swap	Cash flow	760,000		3.06	(1)
						$(40)

As of December 31, 2003, the Company had the following derivative instruments outstanding related to interest rate and foreign currency swaps.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount U.S. $ (In Millions)	Average Underlying Rate	Average Floating Rate	Fair Value Asset (Liability) (In Millions)
2004	Swap	Foreign currency	$ 8	1.43		$ 1
	Interest rate swap	Fair value	50	5.6%	LIBOR + 3.36%	—
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)
						$—

The derivative assets and liabilities represent the market values of the Company's derivative instruments as of December 31, 2003. During the years ended 2003, 2002 and 2001, hedging activities related to cash settlements decreased revenues by $63 million, increased revenues by $114 million and decreased revenues by $322 million, respectively. In addition, during 2002 and 2001, losses of $22 million and gains of $14 million, respectively, were recorded in revenues associated with ineffectiveness of cash-flow and fair-value hedges. During 2003, 2002 and 2001 gains of $9 million, losses of $10 million and gains of $10 million, respectively, were recorded in revenues related to changes in fair value of derivative instruments which do not qualify for hedge accounting.

In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, the Company recorded a net-of-tax cumulative-effect-type loss adjustment of $366 million in Accumulated Other Comprehensive Income to recognize at fair value all derivatives that were designated as cash-flow hedging instruments. The Company recorded cash-flow

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 and foreign currency exchange rate fluctuations. Derivative instruments that meet the hedge criteria in SFAS No. 133 are designated as cash-flow hedges, fair-value hedges, or foreign-currency 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. In addition to hedges of commodity prices, the Company also uses foreign-currency swaps to hedge its exposure to exchange rate fluctuations related to its Canadian subsidiaries.

Cash-Flow Hedges

At December 31, 2003, 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 costless 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, 2003, 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.

In July 2003, the Company entered into 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.

Foreign-Currency Hedges

At December 31, 2003, the Company's foreign-currency hedges consisted of foreign currency swaps used to fix the amount of Canadian dollars a Canadian subsidiary receives on anticipated sales denominated in U.S. dollars.

Derivatives Not Designated as Hedges

At December 31, 2003, the Company's derivative positions included option contracts that are not designated as hedges. These positions were entered into to offset the cost of other option positions that are designated as hedges.

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

Year Ended December 31,	2003	2002	2001
U.S. statutory rate	35.0%	35.0%	35.0%
State income taxes	0.6	1.7	2.3
Taxes on foreign income in excess of U.S. statutory rate	3.9	9.4	8.5
Effect of change in foreign income tax rate(1)	(13.6)	(2.3)	(0.3)
Section 29 tax credits(2)	(1.7)	(0.2)	(2.6)
Cross-border financing benefit(3)	(6.2)	(15.1)	(2.2)
Other(4)	1.7	(8.4)	(2.3)
Effective rate	19.7%	20.1%	38.4%

(1) In 2003, the Government of Canada passed Bill C-48 which reduced the Canadian federal income tax rate for companies in the natural resource sector resulting in a benefit of $203 million (−12.9%) to the Company. The Company also recorded a benefit of $11 million (−0.7%) and $26 million (−4.5%) in 2003 and 2002, respectively, due to reductions in the Alberta provincial corporate income tax rate in Canada. Also 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 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 federal income tax audit. 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 audit. Adjustments related to section 29 tax credit certification issues of $7 million (−0.7%) were made in 2001.

(3) The Company recorded benefits of $97 million, $86 million and $20 million in 2003, 2002 and 2001, respectively, related to interest deductions allowed in both the U.S. and Canada.

(4) 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,	2003	2002
	(In Millions)	
Deferred income tax liabilities		
Property, plant and equipment	$1,972	$1,629
Financial accruals and other	391	119
	2,363	1,748
Deferred income tax assets		
Alternative minimum tax (AMT) credit carryforward	(277)	(307)
Foreign net operating loss carryforwards	(150)	(17)
Commodity hedging contracts and other derivatives	(13)	(21)
	(440)	(345)
Less: valuation allowance	25	33
Deferred income taxes	$1,948	$1,436

The net deferred income tax liabilities at December 31, 2003 and 2002 include deferred state income tax liabilities of approximately $56 million and $53 million, respectively. The net deferred income tax liabilities also include foreign tax liabilities of approximately $1,564 million and $1,119 million at December 31, 2003 and 2002, 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. It is not practicable to estimate the deferred tax liability related to such undistributed earnings. At December 31, 2003, undistributed earnings for which a U.S. deferred income tax liability has not been recognized total $1,033 million.

The AMT credit carryforward, related primarily to nonconventional fuel tax credits, is available to offset future federal income tax liabilities. The AMT credit carryforward has no expiration date. Of the $150 million tax benefit for operating loss carryforwards, which relate to foreign jurisdictions, $124 million has no expiration date and $26 million will expire between 2004 and 2009.

Other properties consisted of the following.

December 31,	Depreciable Life-Years	2003	2002
		(In Millions)	
Plants and pipeline systems	10-20	$1,018	$ 804
Land, buildings, improvements and furniture and fixtures	0-40	128	111
Data processing and telecommunications equipment	3-7	159	152
Other	3-15	76	73
		1,381	1,140
Accumulated depreciation		362	276
Other properties — net		$1,019	$ 864

6. Accounts Payable

Accounts payable consisted of the following.

December 31,	2003	2002
	(In Millions)	
Trade payables	$ 67	$ 49
Accrued expenses	478	617
Revenues and royalties payable to others	98	86
Accrued payroll	44	42
Other	27	15
Accounts payable	$714	$809

7. Income Taxes

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

Year Ended December 31,	2003	2002	2001
		(In Millions)	
Domestic	$ 983	$548	$470
Foreign	587	21	437
Total	$1,570	$569	$907

The provision for income taxes follows.

Year Ended December 31,	2003	2002	2001
		(In Millions)	
Current			
Federal	$ 84	$ 37	$ 25
State	9	11	19
Foreign	67	28	86
	160	76	130
Deferred			
Federal	85	63	76
State	6	4	14
Foreign	59	(28)	129
	150	39	219
Total	$310	$115	$349

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 and 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 if 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 2003 and determined that the fair value of the Company's Canadian reporting unit exceeded its net book value as of September 30, 2003. 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, change in capital structure, 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.

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, 2002	$803
Changes in foreign exchange rates during the period	179
December 31, 2003	$982

5. Oil and Gas and Other Properties

Oil and gas properties consisted of the following.

December 31,	**2003**	**2002**
	(In Millions)	
Proved properties	$14,588	$11,441
Unproved properties	1,374	1,275
	15,962	12,716
Accumulated depreciation, depletion and amortization	6,670	5,077
Oil and gas properties—net	$ 9,292	$ 7,639

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.

In August 2002, the Company purchased certain oil and gas properties located in Wise and Denton Counties, Texas for $141 million. On January 3, 2002, the Company consummated a property acquisition, for properties located in the Viking-Kinsella area, from ATCO Gas and Pipelines Ltd. (ATCO), a Canadian regulated gas utility, for approximately $344 million.

Acquisition of Hunter

In December 2001, BR acquired all of the outstanding shares of Hunter valued at approximately U.S. $2.1 billion, resulting in goodwill of approximately $793 million. All of the goodwill was assigned to the Company's Canadian reporting unit. This acquisition was funded with cash on hand and proceeds from the issuances of $1.5 billion of fixed-rate notes and $400 million of commercial paper. The transaction was accounted for under the purchase method in accordance with SFAS No. 141. The results of operations of Hunter were included in the Company's financial statements effective December 2001.

The following table presents the unaudited pro forma results of the Company as though the acquisition had occurred on January 1, 2001. Pro forma results are not necessarily indicative of actual results.

Year Ended December 31, 2001	(In Millions, Except per Share Amounts)
Revenues	$3,902
Net income	696
Basic earnings per common share	3.36
Diluted earnings per common share	$ 3.34

Divestitures

In October 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its asset portfolio, primarily in the U.S. During 2002, the Company completed the sale of the Val Verde Plant and certain 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,	**2003**	**2002**
	(In Millions)	
Natural gas, NGLs and crude oil revenue sales	$508	$410
Joint interest billings	93	99
Other	17	17
	618	526
Less: allowance for doubtful accounts	13	11
Accounts receivable	$605	$515

4. Goodwill

The entire goodwill balance of $982 million at December 31, 2003, which is not deductible for tax purposes, is related to the 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

The weighted average fair values of options granted during the years 2003, 2002 and 2001 were $10.85, $10.83 and $13.35, respectively. The fair values of employee stock options were calculated using a variation of the Black-Scholes stock option valuation model with the following weighted average assumptions for grants in 2003, 2002 and 2001: stock price volatility of 32 percent, 31 percent and 35 percent, respectively; risk free rate of return ranging from 2.5 percent to 5 percent; dividend yields of 1.18 percent, 1.43 percent and 1.32 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 stock-based employee compensation.

Year Ended December 31,	**2003**	**2002**	**2001**
	(In Millions, Except per Share Amounts)		
Net income—as reported	$1,201	$ 454	$ 561
Less: pro forma stock based employee compensation cost, after tax (unaudited)	10	11	12
Net income—pro forma (unaudited)	$1,191	$ 443	$ 549
Basic EPS—as reported	$ 6.03	$ 2.26	$ 2.71
Basic EPS—pro forma (unaudited)	5.98	2.21	2.65
Diluted EPS—as reported	6.00	2.25	2.70
Diluted EPS—pro forma (unaudited)	$ 5.95	$ 2.20	$ 2.64

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 199 million, 201 million and 207 million for the years ended December 31, 2003, 2002 and 2001, 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 200 million, 202 million and 208 million for the years ended December 31, 2003, 2002 and 2001, respectively. For the years ended December 31, 2003, 2002 and 2001, approximately 1 million, 4 million and 4 million shares, respectively, attributable to the 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 reserve volumes and the future development, dismantlement and abandonment costs, estimates relating to certain natural gas, NGLs and crude oil revenues and expenses as well as estimates related to deferred income taxes. Actual results could differ from those estimates.

2. Business Combination and Other Property Acquisitions and Divestitures

Other 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 in net income for the years ended December 31, 2003, 2002 and 2001 are losses of $7 million, $1 million and $7 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. On January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. In accordance with SFAS No. 133, 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.

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, 2003, 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.

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.

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 on 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 and 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, 2003 and 2002, the Company had net gas imbalance receivables of $19 million.

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 in the 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 (Loss). At December 31, 2003 and 2002, the balance in Accumulated Other Comprehensive Income (Loss) related to foreign currency translation was a gain of $676 million and a loss of $126 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 foreign entities other than BR's Canadian operating subsidiaries are measured using the U.S. dollar as the functional currency. For 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

1. Accounting Policies

Nature of Business

Burlington Resources Inc. (BR) is a holding company engaged, through its principal subsidiaries, 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), in the exploration for and the development, production and marketing of natural gas, NGLs and crude oil. BR ranks 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. Its extensive North American lease holdings extend from the U.S. Gulf Coast to the Arctic coast of Canada. The Company's North American operations include a mix of production, development and exploration assets. International operations focus on Northwest Europe, North Africa, China, and South America.

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.

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,	**2003**	**2002**
	(In Millions)	
Materials and supplies	$70	$43
Product inventory	3	5
Inventories	$73	$48

Properties

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. Costs of unproved properties (lease acquisition costs) are capitalized and amortized on a composite basis, based on past success, experience and average lease term lives.

The Company evaluates the impairment of its 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 NYMEX 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.

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, 2000	$2	$3,944	$ 884	$ (5)	$ (70)	$(1,005)	$3,750
Comprehensive Income (Loss)							
Net Income			561				561
Foreign Currency Translation					(90)		(90)
Cumulative Effect of Change in Accounting Principle— Hedging					(366)		(366)
Hedging Activities					420		420
Comprehensive Income (Loss)			561		(36)		525
Cash Dividends Declared ($0.55 per Share)			(113)				(113)
Common Stock Purchases (16,092,000 Shares)						(684)	(684)
Stock Option Activity						41	41
Issuance of Restricted Stock				(10)		10	—
Amortization of Restricted Stock				6			6
December 31, 2001	2	3,944	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 ($0.55 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	2	3,941	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 ($0.58 per Share)			(115)				(115)
Common Stock Purchases (7,414,990 Shares)						(361)	(361)
Stock Option Activity		5				129	134
Issuance of Restricted Stock				(12)		12	—
Amortization of Restricted Stock				11			11
December 31, 2003	**$2**	**$3,946**	**$2,761**	**$(10)**	**$ 655**	**$(1,833)**	**$5,521**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

Year Ended December 31,	2003	2002	2001
		(In Millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,201	$ 454	$ 561
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	927	833	735
Deferred Income Taxes	150	39	219
Exploration Costs	252	286	258
Impairment of Oil and Gas Properties	63	—	184
Gain on Disposal of Assets	(8)	(68)	(8)
Changes in Derivative Fair Values	(5)	32	(25)
Cumulative Effect of Change in Accounting Principle—Net	59	—	(3)
Working Capital Changes, Net of Acquisition			
Accounts Receivable	(28)	(117)	467
Inventories	(18)	2	6
Other Current Assets	(23)	(17)	(3)
Accounts Payable	(4)	138	(187)
Taxes Payable	(9)	43	(46)
Accrued Interest	(1)	4	23
Other Current Liabilities	—	(8)	(2)
Changes in Other Assets and Liabilities	(17)	(72)	(73)
Net Cash Provided by Operating Activities	2,539	1,549	2,106
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Properties	(1,899)	(1,851)	(1,293)
Acquisition of Hunter, Net of Cash Acquired	—	—	(2,087)
Proceeds from Sales and Other	4	1,180	1
Net Cash Used in Investing Activities	(1,895)	(671)	(3,379)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-term Debt	—	454	2,247
Reduction in Long-term Debt	(75)	(879)	(211)
Dividends Paid	(85)	(139)	(116)
Common Stock Purchases	(356)	—	(684)
Common Stock Issuances	128	13	41
Debt Issuance Costs and Other	(3)	2	(20)
Net Cash Provided by (Used in) Financing Activities	(391)	(549)	1,257
Effect of Exchange Rate Changes on Cash and Cash Equivalents	61	(2)	—
Increase (Decrease) in Cash and Cash Equivalents	314	327	(16)
Cash and Cash Equivalents			
Beginning of Year	443	116	132
End of Year	**$ 757**	**$ 443**	**$ 116**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET

December 31,	2003	2002
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 757	$ 443
Accounts Receivable	605	515
Inventories	73	48
Other Current Assets	82	55
	1,517	1,061
Oil and Gas Properties (Successful Efforts Method)	15,962	12,716
Other Properties	1,381	1,140
	17,343	13,856
Accumulated Depreciation, Depletion and Amortization	7,032	5,353
Properties—Net	10,311	8,503
Goodwill	982	803
Other Assets	185	278
Total Assets	**$ 12,995**	**$ 10,645**
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 714	$ 809
Taxes Payable	43	44
Accrued Interest	61	61
Dividends Payable	30	—
Other Current Liabilities	43	45
Current Maturities of Long-term Debt	—	63
	891	1,022
Long-term Debt	3,873	3,853
Deferred Income Taxes	1,948	1,436
Commodity Hedging Contracts and Other Derivatives	17	33
Other Liabilities and Deferred Credits	745	469
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 $.01 per Share (Authorized 325,000,000 Shares; Issued 241,188,688 Shares for both 2003 and 2002)	2	2
Paid-in Capital	3,946	3,941
Retained Earnings	2,761	1,675
Deferred Compensation—Restricted Stock	(10)	(9)
Accumulated Other Comprehensive Income (Loss)	655	(164)
Cost of Treasury Stock (43,539,885 and 39,749,431 Shares for 2003 and 2002, respectively)	(1,833)	(1,613)
Stockholders' Equity	5,521	3,832
Total Liabilities and Stockholders' Equity	**$ 12,995**	**$ 10,645**

See accompanying Notes to Consolidated Financial Statements.

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

Year Ended December 31,	**2003**	**2002**	**2001**
	(In Millions, Except per Share Amounts)		
REVENUES	**$ 4,311**	**$ 2,968**	**$ 3,419**
COSTS AND OTHER INCOME—NET			
Taxes Other than Income Taxes	187	123	166
Transportation Expense	408	354	337
Production and Processing	475	467	505
Depreciation, Depletion and Amortization	927	833	735
Exploration Costs	252	286	258
Impairment of Oil and Gas Properties	63	—	184
Administrative	164	161	149
Interest Expense	260	274	190
Gain on Disposal of Assets	(8)	(68)	(8)
Other Expense (Income)—Net	13	(31)	(4)
Total Costs and Other Income—Net	**2,741**	**2,399**	**2,512**
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	1,570	569	907
Income Tax Expense	310	115	349
Income Before Cumulative Effect of Change in Accounting Principle	1,260	454	558
Cumulative Effect of Change in Accounting Principle—Net	(59)	—	3
Net Income	**$ 1,201**	**$ 454**	**$ 561**
EARNINGS PER COMMON SHARE			
Basic			
Before Cumulative Effect of Change in Accounting Principle	$ 6.33	$ 2.26	$ 2.70
Cumulative Effect of Change in Accounting Principle—Net	(0.30)	—	0.01
Net Income	**$ 6.03**	**$ 2.26**	**$ 2.71**
Diluted			
Before Cumulative Effect of Change in Accounting Principle	$ 6.30	$ 2.25	$ 2.69
Cumulative Effect of Change in Accounting Principle—Net	(0.30)	—	0.01
Net Income	**$ 6.00**	**$ 2.25**	**$ 2.70**

See accompanying Notes to Consolidated Financial Statements.

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.

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, 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. 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.

amends certain other existing pronouncements. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. In addition, with some exceptions, all provisions of SFAS No. 149 should be applied prospectively. The adoption of SFAS No. 149 did not have a material impact on the Company's consolidated financial position or results of operations.

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 and/or cause it to curtail capital spending projects and delay or defer exploration, exploitation or development projects.

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, "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 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 and high associated costs can be incurred in the process of seeking commercial discoveries.

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 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.

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.

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.

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 $263.6 million in principal, plus interest, 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 this matter will be scheduled for trial during 2004. The Company currently does not believe that an unfavorable outcome is probable nor, in the event of an unfavorable outcome, is the Company reasonably able to estimate the possible loss, if any, or range of loss in these lawsuits. Accordingly, there has been no reserve established for this matter.

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.

The Company has established reserves for certain legal proceedings which are 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 with respect to those matters in which reserves have been established of up to approximately $25 million to $30 million in excess of the amounts currently accrued. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued.

While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these legal proceedings 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.

Other Matters

Recent Accounting Pronouncements

On December 23, 2003, the FASB issued SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88, and 106. This statement revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, Employers' Accounting for Pensions,* No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,* and No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* The new rules require additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. The new disclosures are effective for 2003 calendar year-end financial statements. The Company has adopted the revised disclosures as of December 31, 2003. See Note 13 of Notes to Consolidated Financial Statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS No. 150). SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. It is to be implemented by reporting the cumulative effect of a change in an accounting principle for financial instruments created before the issuance date of SFAS No. 150 and still existing at the beginning of the interim period of adoption. Restatement is not permitted. The adoption of SFAS No. 150 during 2003 did not impact the Company's consolidated financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities* (SFAS No. 149). SFAS No. 149 improves financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. In particular, SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an "underlying" to conform it to language used in FIN No. 45 and 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. The cases alleging improper measurement techniques remain pending in MDL-1293.

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 $68 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could also 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. 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. The Company currently does not believe that an unfavorable outcome is probable nor, in the event of an unfavorable outcome, is the Company reasonably able to estimate the possible loss, if any, or range of loss in this lawsuit. Accordingly, there has been no reserve established for this matter.

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 1983 to the present on natural gas produced from specified wells in Oklahoma through the use of below-

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

Total Costs and Other Income–Net

Year Ended December 31,	2002	2001	2000	2002 vs. 2001 Increase (Decrease)	2002 vs. 2001 % Increase (Decrease)
			($ In Millions)		
Costs and other income – net					
Taxes other than income taxes	$ 123	$ 166	$ 159	$ (43)	(26)%
Transportation expense	354	337	305	17	5
Production and processing	467	505	470	(38)	(8)
Depreciation, depletion & amortization	833	735	710	98	13
Exploration costs	286	258	237	28	11
Impairment of oil and gas properties	—	184	—	(184)	(100)
Administrative	161	149	146	12	8
Interest expense	274	190	197	84	44
Gain on disposal of assets	(68)	(8)	(2)	(60)	750
Other expense (income) – net	(31)	(4)	29	(27)	675
Total costs and other income – net	**$ 2,399**	**$ 2,512**	**$ 2,251**	**$ (113)**	**(4)%**

Total costs and other income—net decreased $113 million in 2002. The decrease included a $184 million charge related to the impairment of oil and gas properties held for sale and a restructuring charge of $10 million related to severance and other exit costs recorded in 2001.

DD&A increased $98 million in 2002 primarily due to a higher unit-of-production rate related to changes in production resulting from the Canadian acquisitions, which had higher rates than the average unit-of-production rates for the Company. DD&A also increased due to higher natural gas production volumes primarily in Canada.

Interest expense increased $84 million primarily due to higher debt balances during 2002 resulting from the Hunter acquisition in late 2001 and other property acquisitions consummated in early 2002.

Exploration costs increased $28 million in 2002 primarily due to higher amortization of undeveloped lease costs of $54 million, higher drilling rig costs of $17 million and higher G&G and other expenses of $20 million partially offset by lower exploratory dry hole costs of $63 million. The higher drilling rig expenses, which were approximately $40 million during 2002, were attributable to the subletting of a deepwater drilling rig under lease to the Company. This $40 million charge covered the anticipated loss for the remaining term of the lease.

Transportation expense increased $17 million primarily due to higher contract rates, and administrative expenses increased $12 million primarily due to higher payroll and benefits.

Gain on disposal of assets increased $60 million due to the divestiture of Val Verde and non-core, non-strategic properties in 2002. Taxes other than income taxes decreased $43 million primarily due to lower crude oil and natural gas revenues, and production and processing expenses decreased $38 million, including the $10 million restructuring charge recorded in 2001, primarily due to lower well operating costs. Other income—net increased $27 million primarily due to higher interest income, lower foreign currency transaction losses and lower miscellaneous expenses incurred in 2002.

Income Tax Expense

Income tax expense decreased $234 million in 2002. The decrease in tax expense was primarily due to lower pretax income of $338 million. In 2002, the Company recorded a benefit of $27 million associated with the reversal of a tax valuation allowance related to the sale of assets in the U.K. sector of the North Sea. During 2002, the Company recorded higher tax benefits of $86 million related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing. The Company also recorded higher tax benefits of $23 million as a result of a reduction in the Alberta provincial corporate income tax rate in Canada. These benefit increases were partially offset by lower net Section 29 Tax Credits of $23 million and higher tax expense of $12 million related to an increase in the U.K.'s income tax rate.

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

Revenue Variances

Year ended December 31,	2002	2001	2000	2002 vs. 2001 Increase (Decrease)	2002 vs. 2001 % Increase (Decrease)
			($ In Millions)		
Natural gas	$ 2,209	$ 2,510	$ 2,136	$ (301)	(12)%
NGLs	317	289	337	28	10
Crude oil	432	540	686	(108)	(20)
Processing and other	10	80	59	(70)	(88)
Total revenues	**$ 2,968**	**$ 3,419**	**$ 3,218**	**$ (451)**	**(13)%**

Revenues

The Company's consolidated revenues decreased $451 million in 2002. Lower revenues were primarily driven by reduced commodity prices, resulting in reduced revenues of $619 million. Processing and other revenues, which represented less than one percent of the Company's total revenues in 2002, declined $70 million. This decline was primarily due to a reduction in revenues of $31 million and $20 million, respectively, related to ineffectiveness on cash-flow and fair-value hedges and changes in the fair value of derivative instruments that do not qualify for hedge accounting. Processing and other revenues also declined $22 million due to the sale of Val Verde in the second quarter of 2002. These amounts were partially offset by an increase of $241 million related to higher sales volumes. Revenue variances related to commodity prices and sales volumes are described below.

Price Variances

Lower commodity prices resulted in reduced revenues of $619 million in 2002. Average natural gas prices, including a $0.16 realized gain per MCF related to hedging activities, decreased $0.83 per MCF resulting in lower revenues of $580 million. Lower average natural gas prices were impacted by location basis differentials that varied widely compared to the same period in 2001 primarily in the western U.S. and western Canada. Average NGLs prices declined $2.33 per barrel while average crude oil prices, including an $0.18 realized gain per barrel related to hedging activities, increased $0.66 per barrel in 2002. The decline in NGLs prices reduced revenues $51 million while the increase in crude oil prices increased revenues $12 million in 2002.

Volume Variances

Higher sales volumes resulted in increased revenues of $241 million in 2002. Average natural gas sales volumes increased 192 MMCF per day resulting in higher revenues of $282 million. In Canada, average natural gas sales volumes increased 369 MMCF per day primarily due to the acquisitions of Canadian Hunter Exploration Ltd. (Hunter) in late 2001 and ATCO in early 2002 and its drilling program. The increase in natural gas sales volumes was partially offset by reductions of 172 MMCF per day resulting from natural declines in production and asset sales in the Onshore Gulf Coast, the Gulf of Mexico Shelf, the San Juan Basin and the Permian Basin. Average NGLs sales volumes increased 13.0 MBbls per day, resulting in increased revenues of $80 million in 2002. Average NGLs sales volumes increased 14.9 MBbls per day also primarily due to the acquisition of Hunter. Average crude oil sales volumes decreased 14.1 MBbls per day, resulting in reduced revenues of $121 million in 2002. Average crude oil sales volumes decreased 12.4 MBbls per day primarily due to natural declines in production and asset sales in the Gulf of Mexico Shelf, Canada and the Permian Basin.

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 Val Verde in 2002. Other expense—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 geological and geophysical (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 five years 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. 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.

Year Ended December 31, 2002 Compared With Year Ended December 31, 2001

The Company's consolidated net income decreased $107 million or $0.45 diluted earnings per common share in 2002 primarily as a result of lower commodity prices partially offset by higher commodity sales volumes. Net income also included a benefit of $27 million or $0.13 diluted earnings per common share as a result of the reversal of a tax valuation reserve related to the sale of assets in the U.K. sector of the North Sea and a tax benefit of $26 million or $0.13 diluted earnings per common share related to the reduction of the Alberta corporate income tax rate in Canada.

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

Price and Volume Variances

				2002 vs. 2001		
Year Ended December 31,	**2002**	**2001**	**2000**	**Increase (Decrease)**	**% Increase (Decrease)**	**Increase (Decrease)**
						(In Millions)
Price Variance						
Natural gas sales prices (per MCF)	$ 3.20	$ 4.03	$ 3.42	$ (0.83)	(21)%	$ (580)
NGLs sales prices (per Bbl)	14.46	16.79	19.51	(2.33)	(14)	(51)
Crude oil sales prices (per Bbl)	$ 24.11	$ 23.45	$ 25.44	$ 0.66	3%	12
Total price variance						**$ (619)**
Volume Variance						
Natural gas sales volumes (MMCF per day)	1,916	1,724	1,724	192	11%	$ 282
NGLs sales volumes (MBbls per day)	60.1	47.1	47.2	13.0	28	80
Crude oil sales volumes (MBbls per day)	49.1	63.2	73.7	(14.1)	(22)%	(121)
Total volume variance						**$ 241**

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 17 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**	**2001**	**Increase (Decrease)**	**% Increase (Decrease)**
			($ In Millions)		
Costs and other income - net					
Taxes other than income taxes	$ 187	$ 123	$ 166	$ 64	52%
Transportation expense	408	354	337	54	15
Production and processing	475	467	505	8	2
Depreciation, depletion and amortization	927	833	735	94	11
Exploration costs	252	286	258	(34)	(12)
Impairment of oil and gas properties	63	—	184	63	—
Administrative	164	161	149	3	2
Interest expense	260	274	190	(14)	(5)
Gain on disposal of assets	(8)	(68)	(8)	60	88
Other expense (income) - net	13	(31)	(4)	44	142
Total costs and other income - net	**$ 2,741**	**$ 2,399**	**$ 2,512**	**$ 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 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 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

Results of Operations

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

The Company's consolidated net income increased $747 million or $3.75 diluted earnings per common share in 2003 primarily due to higher commodity prices. Net income in 2003 included a tax benefit of $214 million or $1.07 diluted earnings per common share related to the reduction of the Canadian federal income tax and the Alberta provincial corporate income tax rates. Net income in 2002 included a tax benefit of $26 million or $0.13 diluted earnings per common 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 $0.13 diluted earnings per common share related to the sale of assets in the United Kingdom (U.K.) sector of the North Sea.

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

Price and Volume Variances

				2003 vs. 2002		
Year Ended December 31,	**2003**	**2002**	**2001**	**Increase (Decrease)**	**(%) Increase (Decrease)**	**Increase (Decrease)**
						(In Millions)
Price Variance						
Natural gas sales prices (per MCF)	$ 4.83	$ 3.20	$ 4.03	$1.63	51%	$ 1,129
NGLs sales prices (per Bbl)	20.40	14.46	16.79	5.94	41	140
Crude oil sales prices (per Bbl)	$27.22	$24.11	$23.45	$3.11	13%	53
Total price variance						**$ 1,322**
Volume Variance						
Natural gas sales volumes (MMCF per day)	1,899	1,916	1,724	(17)	(1)%	$ (20)
NGLs sales volumes (MBbls per day)	64.8	60.1	47.1	4.7	8	25
Crude oil sales volumes (MBbls per day)	46.5	49.1	63.2	(2.6)	(5)%	(23)
Total volume variance						**$ (18)**

Revenue Variances

				2003 vs. 2002	
Year ended December 31,	**2003**	**2002**	**2001**	**Increase**	**% Increase**
			($ In Millions)		
Natural gas	$ 3,331	$ 2,209	$ 2,510	$ 1,122	51%
NGLs	482	317	289	165	52
Crude oil	462	432	540	30	7
Processing and other	36	10	80	26	260
Total revenues	**$ 4,311**	**$ 2,968**	**$ 3,419**	**$ 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 on 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 Val Verde in June 2002. The revenue variances related to commodity prices and sales volumes are described below.

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.

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

In accordance with SFAS No. 5, 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.

Other

SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Intangible Assets,* were issued in June 2001 and became effective for the Company July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report certain intangibles assets separately from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, and included as intangible assets on the Company's consolidated balance sheets. In addition, the disclosures required by SFAS No. 141 and No. 142 related to intangibles would be included in the notes to the consolidated financial statements. Historically, the Company, like many other oil and gas companies, has included oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves as part of the oil and gas properties, even after SFAS No. 141 and No. 142 became effective.

This interpretation of SFAS No. 141 and No. 142 would only affect the Company's consolidated balance sheet classification of oil and gas leaseholds. The Company's results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.*

At December 31, 2003, the Company had undeveloped and developed leaseholds of approximately $1.3 billion and $2.4 billion that would have been classified on the consolidated balance sheet as intangible undeveloped leaseholds and intangible developed leaseholds, respectively, if it had applied the interpretation currently being discussed. The Company will continue to classify its oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as oil and gas properties until further guidance is provided.

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. 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 for its exploration and development activities. Acquisition and development costs are capitalized and amortized using the unit-of-production method based on proved and proved developed reserves estimated by the Company's reserve engineers. Changes in reserve quantities as described below 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 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 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. See Note 16 of Notes to Consolidated Financial Statements for impairment of oil and gas properties.

Costs attributable to the Company's unproved properties 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. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year 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 an 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. Inherent in the present value calculation are 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. 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.

Goodwill

As described in Note 4 of Notes to Consolidated Financial Statements, the Company accounts for goodwill in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires an annual impairment assessment in lieu of periodic amortization. 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, change in capital structure or depressed natural gas, NGLs and crude oil prices could lead to an impairment of all or a portion of goodwill

December 31, 2003, 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 $35 million decrease in the net unrealized gain. The derivative instruments in place at December 31, 2003 hedged approximately 13 percent of the Company's expected natural gas production volumes through 2004.

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 the 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 established formal internal control procedures which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to counterparties through formal credit policies and monitoring procedures. In the normal course of business, collateral is not required for financial instruments with credit risk.

Foreign Currency Risk

The Company's reported cash flows related to its Canadian operating subsidiaries are based on cash flows measured in Canadian dollars and converted to the U.S. dollar equivalent based on the average of the Canadian to U.S. dollar exchange rates for the period reported. The Company's Canadian operating subsidiaries have no financial obligations that are denominated in U.S. dollars.

Dividends

On January 21, 2004, the Board of Directors (Board) declared a common stock quarterly cash dividend of $0.15 per share, payable April 9, 2004 to shareholders of record on March 10, 2004. 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 $115 million and $85 million, respectively, during 2003.

On January 21, 2004, the Company's Board also announced a 2-for-1 split (Split) on the Company's Common Stock in the form of a share distribution payable on June 1, 2004 to shareholders of record on May 5, 2004. The Split is 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.

Application of Critical Accounting Policies

Oil and Gas Reserves

The Company's estimate of proved reserves reflects quantities of natural gas, crude oil and NGLs 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, operating costs, development costs, production tax rates 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 perform and oversee reserve estimates. Additionally, more than 80 percent of the Company's reserve estimates during 2001, 2002 and 2003 were subjected to external review by independent oil and gas consultants, who in their judgement determined the estimates to be reasonable in the aggregate. For more information, see independent oil and gas consultants letters on page 63.

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 average annual production growth. Capital expenditures in 2004, excluding proved property acquisitions, are expected to be approximately $1.5 billion, essentially the same as 2003. Capital expenditures in 2004 are expected to be primarily for internal development and exploration of oil and gas properties. Capital spending in 2004 related to internal development and exploration is expected to be about 3 percent higher than 2003. Capital expenditures are expected to be funded from internally generated cash flows.

In October 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its asset portfolio primarily in the U.S. During 2002, the Company completed the sale of the Val Verde Plant (Val Verde) and certain 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 during 2002 contributed approximately 230 MMCFE and 458 MMCFE per day during the years 2002 and 2001, respectively. 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.

Other International

The Company's Other 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 local 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 the "basis differential." Basis differentials can vary widely depending on various factors, including but not limited to, local supply and demand.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires enterprises to recognize all derivatives as either assets or liabilities on the balance sheet and measure 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 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 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

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 exploration and development programs where governmental organizations require such support.

Changes in credit rating also impact the cost of borrowing under the Company's Revolvers, but have no impact on availability of credit under the agreements. The Revolvers are filed as exhibits 10.17, 10.18 and 10.28 to this Form 10-K.

In December 2000, the Company's Board of Directors 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 of Directors voted to restore the authorization level to $1 billion effective May 1, 2003.

During 2003, the Company repurchased approximately 7 million shares of its Common Stock for approximately $361 million and, as of December 31, 2003, had authority to repurchase an additional $762 million of its Common Stock under the current authorization. As of December 31, 2003, $5 million of the share repurchases were not cash settled during the period. Since December 2000, the Company has repurchased approximately 24 million shares or $1 billion of its Common Stock.

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 current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. The Company has investments in two entities that it 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 $16 million and $2 million, respectively. As of December 31, 2003, Lost Creek had outstanding debt totaling $48 million and Evangeline had outstanding debt totaling $38 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.

Capital Expenditures Variances

				2003 vs. 2002		2003 vs. 2001	
Year Ended December 31,	**2003**	**2002**	**2001**	**Increase (Decrease)**	**(%) Increase (Decrease)**	**Increase (Decrease)**	**(%) Increase (Decrease)**
				($ In Millions)			
Oil and gas							
Development	$ 1,056	$ 779	$ 826	$ 277	36%	$ 230	28%
Exploration	301	218	259	83	38	42	16
Acquisitions	228	604	1,997	(376)	(62)	(1,769)	(89)
Total oil and gas	**1,585**	**1,601**	**3,082**	**(16)**	**(1)**	**(1,497)**	**(49)**
Plants and pipelines	163	193	346	(30)	(16)	(183)	(53)
Administrative and other	40	43	26	(3)	(7)	14	54
Total capital expenditures	**$ 1,788**	**$ 1,837**	**$ 3,454**	**$ (49)**	**(3)%**	**$ (1,666)**	**(48)%**

The Company's consolidated capital expenditures were down 3 percent and 48 percent compared to 2002 and 2001, respectively. Year 2001 includes the Hunter acquisition. The Company utilizes a disciplined approach to capital spending. Excluding acquisitions, the Company's capital spending related to internal development and exploration is up 36 and 25 percent compared to 2002 and 2001, respectively. However, at the current capital spending levels, the Company believes that spending is sufficient to add adequate reserves and achieve the target of three to eight percent

Net cash provided by operating activities in 2003 increased $990 million and $433 million over 2002 and 2001, respectively, primarily due to higher commodity prices. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Average natural gas prices increased 51 percent and 20 percent over 2002 and 2001, respectively, while NGLs prices increased 41 percent and 22 percent over the same period. Production volumes were essentially flat to 2002 but up 8 percent over 2001. While the Company believes that 2004 production will exceed 2003 levels, the Company 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. See page 17 for a discussion of commodity prices.

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, 2003 was 142 percent and has averaged 187 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 2004.

The Company has various commitments 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 commitments with cash generated from operations. The following table summarizes the Company's contractual obligations at December 31, 2003.

		Payments Due by Period			
Contractual Obligation	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(In Millions)		
Total debt(1)	$3,916	$ —	$500	$466	$2,950
Transportation demand charges(2)	933	160	317	131	325
Non-cancellable operating leases(2)	291	36	81	51	123
Pension funding(3)	11	11	—	—	—
Drilling rig commitments(2)	28	27	1	—	—
Total Contractual Obligations	**$5,179**	**$234**	**$899**	**$648**	**$3,398**

(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) The Company expects to contribute $11 million to its U.S. pension plans in 2004. See Note 13 of Notes to Consolidated Financial Statements for discussion of the Company's pension plans.

The Company also has liabilities of $28 million related to postretirement benefits on its Consolidated Balance Sheet at December 31, 2003. Due to the nature of these benefits, the Company cannot determine precisely when the payments will be made for these benefits. See Note 13 of Notes to Consolidated Financial Statements for discussion of postretirement benefits.

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, two long-term natural gas transportation agreements and a natural gas purchase agreement. 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.

While the mark-to-market positions under the hedging agreements and the natural gas purchase agreement 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, 2003, the aggregate unfavorable mark-to-market position under the aforementioned hedging agreements was approximately $13 million. A rating change would have had no impact on the Company related to the natural gas purchase agreement since the mark-to-market position under such agreement was favorable to the Company. 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 $31 million as of December 31, 2003.

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.

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 changes, 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 2003, the Company estimates that a $0.10 per MCF change in natural gas prices would have an impact on annual revenues of approximately $69 million. Also, based on average daily crude oil production in 2003, the Company estimates that a $1.00 per barrel change in crude oil prices would have an impact on annual revenues of approximately $17 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[SM] 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 very disciplined approach to property acquisitions, making it very 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, 2003 and December 31, 2002 was 41 percent and 51 percent, respectively. In December 2003, the Company retired Canadian $100 million (U.S. $75 million) of 6.40% Notes. The 20 percent reduction in total debt to total capital was attributable to the Company's strong net income, coupled with the strength of the Canadian currency and the retirement of debt 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 2004 capital expenditures, excluding any potential major acquisition(s). At December 31, 2003, the Company had $757 million of cash and cash equivalents on hand.

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. 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 had credit commitments in the form of revolving credit facilities (Revolvers) as of December 31, 2003. The Revolvers are comprised of agreements for $600 million, $400 million and Canadian $390 million (U.S. $300 million). The $600 million Revolver expires in December 2006 and the $400 million and Canadian $390 million Revolvers expire in December 2004 unless renewed by mutual consent. The Company has the option to convert any remaining balances on the $400 million and Canadian $390 million Revolvers to one-year and five-year plus one day term notes, respectively. Under the covenants of the Revolvers, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements). The Revolvers are available to cover debt due within one year. Therefore, commercial paper, if any, credit facility notes and fixed-rate debt due within one year are generally classified as long-term debt. At December 31, 2003, there were no amounts outstanding under the Revolvers and no outstanding commercial paper.

Capital Expenditures

Year Ended December 31,	**2003**	**2002**	**2001** (1)
		(In Millions)	
Total capital expenditures	$1,788	$1,837	$3,454
Less: acquisitions	228	604	1,997
Capital expenditures, excluding acquisitions	**$1,560**	**$1,233**	**$1,457**

(1) Includes the Canadian Hunter Exploration Ltd. (Hunter) acquisition.

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to the Company's long-term success. In 2003, the Company's reserve replacement costs were $1.23 per MCFE excluding acquisitions or $1.19 per MCFE including acquisitions. The Company replaced 142 percent of its worldwide production from all sources and 118 percent of its worldwide production excluding acquisitions during 2003.

In 2004, the Company expects to spend approximately $1.5 billion of capital for oil and gas activities, excluding acquisitions. This level is roughly the same as recent years and represents the level of investment the Company believes is needed in each of the next few years to achieve its stated target of three to eight percent average annual production growth. Approximately 85 percent of the Company's 2004 capital program is allocated to its North American programs in Canada and the U.S. This represents an increase of approximately 10 percent from prior years, primarily due to the fact that significant international project development spending was largely completed in 2003. In North America, in 2004 the Company is allocating a higher percentage of its capital investment to the U.S. given the higher Canadian service costs and the weakening of the U.S. dollar. Below is a discussion of the Company's production growth.

Production

Year Ended December 31,	**2003**	**2002**	**2001**
		(MMCFE per day)	
U.S.	1,265	1,358	1,593
Canada	1,062	1,013	579
Other International	240	200	214
Total production	**2,567**	**2,571**	**2,386**

The Company has a goal to achieve between three and eight percent average annual production growth. In 2003, production volumes were 2,567 MMCFE per day, essentially flat to 2002's volumes. However, when considering production volumes related to assets that were retained following the 2002 divestiture program, production volumes increased about 10 percent compared to 2002. In 2004, the Company expects production volumes to average between 2,665 and 2,879 MMCFE per day. This production growth is expected to be driven by steady production growth in North America and accelerating production growth from several international projects.

In 2004, the Company expects production growth in Canada as a result of the investment in its large repeatable development programs, such as in the Deep Basin. In the U.S., the Company expects production growth as a result of restoring full production at the Madden Field by mid-year 2004, as well as increased production from Cedar Creek, Barnett Shale and south Louisiana drilling programs. Internationally, the Company expects to maintain production in Algeria, increase production in offshore China, and initiate start-up of the sour gas fields in the East Irish Sea by mid-year 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 very significant role in the Company's financial returns, the Company focuses on controllable elements such as certain operating costs. In 2004, the Company expects to keep its operating and administrative costs about the same as 2003 on a per unit of production basis. However, it expects depletion and depreciation expense to increase about 10 to 15 percent in 2004, compared to 2003, as a result of rate changes related to Canadian and other international properties and unfavorable exchange rate impacts. Other costs could also increase as a result of unfavorable exchange rate impacts in Canada. Although subject to the upward cost pressures generally experienced by 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 are 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 each other, 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.

At the Company, there are three types of investment alternatives that constantly compete for available capital. 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 which is 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 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. As of year-end 2003, about 90 percent of the Company's natural gas and crude oil production was in North America. 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. Secondly, the Company has production decline rates that it believes are lower-than-industry-averages. In addition, the Company focuses heavily on maintaining a competitive cost structure. Finally, the Company employs a capital allocation approach that favors discipline and balance.

The Company's international business segment is less mature, but is currently undergoing a significant growth phase following several years of major project development. As a result, the international business is expected to represent about 15 percent of the Company's natural gas and crude oil production in 2004 and remain at a level of 15 percent to 20 percent for the foreseeable future. A discussion of the Company's reserve replacement costs and capital expenditures follow.

Reserve Replacement

Year Ended December 31,	**2003**	**2002**	**2001**(1)
		($ per MCFE)	
Reserve replacement costs, including acquisitions	$1.19	$1.06	$1.34
Reserve replacement costs, excluding acquisitions	$1.23	$1.03	$1.15
		(% of Production)	
Reserve replacement ratio, including acquisitions	142%	161%	264%
Reserve replacement ratio, excluding acquisitions	118%	103%	108%

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 several key international projects. 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 the start-up and delivery of several key projects.

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 crude oil and natural gas 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 excellent relations 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 very disciplined capital allocation process, with the objective of achieving 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 is 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. Each of these factors is challenging and highly variable.

To address subsurface risks, the Company utilizes most 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.

At the Company, managing the commercial risks is an ongoing priority. 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 very 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 provide for sector leading 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 cash operating and administrative costs 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

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.

L. David Hanower, 44—Senior Vice President, Law and Administration, Burlington Resources Inc., July 1998 to present.

John A. Williams, 59—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 AND RELATED STOCKHOLDER MATTERS

The Company's common stock, par value $.01 per share (Common Stock) is traded on the New York Stock Exchange under the symbol "BR" and on the Toronto Stock Exchange under the symbol "B." At December 31, 2003, the number of record holders of Common Stock was 12,631. Information on Common Stock prices and quarterly dividends is shown on page 73 under the subheading "Quarterly Financial Data—Unaudited." See also "Equity Compensation Plan Information" under Part III, Item 12 of this report.

ITEM SIX

SELECTED FINANCIAL DATA

The selected financial data for the Company set forth below for the five years ended December 31, 2003 should be read in conjunction with the consolidated financial statements and accompanying notes thereto.

	2003	**2002**	**2001**	**2000**	**1999**
	(In Millions, Except per Share Amounts)				
INCOME STATEMENT DATA					
Revenues	$ 4,311	$ 2,968	$ 3,419	$3,218	$2,359
Income (Loss) Before Income Taxes and Cumulative Effect of Change in Accounting Principle	1,570	569	907	967	(13)
Cumulative Effect of Change in Accounting Principle—Net	(59)	—	3	—	—
Net Income (Loss) (1)	1,201	454	561	675	(10)
Basic Earnings (Loss) per Common Share (1) (2)	6.03	2.26	2.71	3.13	(0.05)
Diluted Earnings (Loss) per Common Share (1) (2)	6.00	2.25	2.70	3.12	(0.05)
Cash Dividends Declared per Common Share	$ 0.58	$ 0.55	$ 0.55	$ 0.55	$ 0.46
BALANCE SHEET DATA					
Total Assets	$12,995	$10,645	$10,582	$7,506	$7,165
Long-term Debt	3,873	3,853	4,337	2,301	2,769
Stockholders' Equity	$ 5,521	$ 3,832	$ 3,525	$3,750	$3,229
Common Shares Outstanding	198	201	201	216	216

(1) Year 2003 includes an adjustment of $203 million or $1.02 per share related to the Canadian federal income tax rate reduction.

(2) Year 2003 includes a cumulative effect of change in accounting principle (Cumulative Effect) loss of $0.30 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.

the Company's operations in the United States and in most countries in which it operates. 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. 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, because regulatory requirements frequently change and may become more stringent and as with other companies engaged in similar businesses, 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.

Filings of Reserve Estimates With Other Agencies—During 2003, the Company filed estimates of its oil and gas reserves for the year 2002 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 page 70.

Employees

The Company had 2,111 and 2,003 employees at December 31, 2003 and 2002, respectively. At December 31, 2003, 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 2003.

EXECUTIVE OFFICERS OF THE REGISTRANT

Bobby S. Shackouls, 53—Chairman of the Board, President and Chief Executive Officer, Burlington Resources Inc., July 1997 to present.

Randy L. Limbacher, 45—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, 51—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 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, the reclamation and abandonment of wells, sites and facilities 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;
- 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 Enchancement 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 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 continue to evolve. Environmental laws and regulations are expected to have an increasing impact on

Production Unit Costs

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

Year Ended December 31,	2003	2002	2001
		(Per MCFE)	
North America			
U.S.			
Average Production Costs	$0.68	$0.62	$0.69
DD&A Rates	0.62	0.66	0.75
Canada			
Average Production Costs	0.44	0.38	0.65
DD&A Rates	1.19	0.97	0.77
Other International			
Average Production Costs	0.53	0.32	0.21
DD&A Rates	1.14	1.02	1.05
Worldwide			
Average Production Costs	0.57	0.50	0.64
DD&A Rates	$0.91	$0.81	$0.78

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, 2003. 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, 2003	Proved Developed	Proved Undeveloped	Total Proved Reserves
North America			
U.S.			
Natural gas (BCF)	3,715	1,137	4,852
NGLs (MMBbls)	188.6	81.0	269.6
Crude oil (MMBbls)	176.5	6.3	182.8
Total U.S. (BCFE)	5,906	1,660	7,566
Canada			
Natural gas (BCF)	1,837	517	2,354
NGLs (MMBbls)	50.8	10.5	61.3
Crude oil (MMBbls)	13.1	2.6	15.7
Total Canada (BCFE)	2,220	596	2,816
Other International			
Natural gas (BCF)	322	546	868
Crude oil (MMBbls)	50.8	32.8	83.6
Total Other International (BCFE)	627	743	1,370
Worldwide			
Natural gas (BCF)	5,874	2,200	8,074
NGLs (MMBbls)	239.4	91.5	330.9
Crude oil (MMBbls)	240.4	41.7	282.1
Total Worldwide (BCFE)	8,753	2,999	11,752

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, 2003. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and international interests (excluding Canada and Argentina) and Sproule Associates Limited reviewed the Company's interests in Canada and Argentina. 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 page 63.

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, crude oil and NGLs. Competitive factors

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,	2003	2002	2001
North America			
U.S.			
Production			
Natural gas (MMCF per day)	865	949	1,121
NGLs (MBbls per day)	37.4	32.7	34.6
Crude oil (MBbls per day)	29.3	35.4	44.0
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 4.87	$ 3.39	$ 3.99
Natural gas, (gain) loss on hedging (per MCF)	0.10	(0.25)	0.78
Natural gas, excluding hedging (per MCF)	4.97	3.14	4.77
NGLs (per Bbl)	18.42	13.23	14.75
Crude oil, including hedging (per Bbl)	28.08	23.16	22.63
Crude oil, (gain) loss on hedging (per Bbl)	0.14	(0.24)	1.58
Crude oil, excluding hedging (per Bbl)	$28.22	$22.92	$24.21
Canada			
Production			
Natural gas (MMCF per day)	867	802	433
NGLs (MBbls per day)	27.4	27.4	12.5
Crude oil (MBbls per day)	5.1	7.8	11.9
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 5.12	$ 3.17	$ 4.60
Natural gas, (gain) loss on hedging (per MCF)	0.10	(0.06)	(0.12)
Natural gas, excluding hedging (per MCF)	5.22	3.11	4.48
NGLs (per Bbl)	23.08	15.92	22.50
Crude oil (per Bbl)	$31.11	$28.32	$26.51
Other International			
Production			
Natural gas (MMCF per day)	167	165	170
Crude oil (MBbls per day)	12.1	5.9	7.3
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 3.07	$ 2.27	$ 2.83
Natural gas, gain on hedging (per MCF)	—	(0.08)	—
Natural gas, excluding hedging (per MCF)	3.07	2.19	2.83
Crude oil (per Bbl)	$23.49	$24.30	$23.42
Worldwide			
Production			
Natural gas (MMCF per day)	1,899	1,916	1,724
NGLs (MBbls per day)	64.8	60.1	47.1
Crude oil (MBbls per day)	46.5	49.1	63.2
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 4.83	$ 3.20	$ 4.03
Natural gas, (gain) loss on hedging (per MCF)	0.09	(0.16)	0.48
Natural gas, excluding hedging (per MCF)	4.92	3.04	4.51
NGLs (per Bbl)	20.40	14.46	16.79
Crude oil, including hedging (per Bbl)	27.22	24.11	23.45
Crude oil, (gain) loss on hedging (per Bbl)	0.09	(0.18)	1.10
Crude oil, excluding hedging (per Bbl)	$27.31	$23.93	$24.55

Acreage

Working interests in developed and undeveloped acreage at December 31, 2003 follow.

December 31, 2003	Gross	Net
North America		
U.S.		
Developed Acres	4,540,807	2,572,817
Undeveloped Acres	10,028,439	8,476,943
Canada		
Developed Acres	3,164,084	2,140,589
Undeveloped Acres	6,726,455	4,827,171
Other International		
Developed Acres	603,839	186,090
Undeveloped Acres	16,670,502	8,117,222
Worldwide		
Developed Acres	8,308,730	4,899,496
Undeveloped Acres	33,425,396	21,421,336

Capital Expenditures

The Company's capital expenditures follow.

Year Ended December 31,	2003	2002	2001
		($ Millions)	
North America			
U.S.			
Oil and Gas Activities	$ 540	$ 463	$ 583
Plants & Pipelines	5	28	70
Administrative	23	35	20
Total U.S.	568	526	673
Canada			
Oil and Gas Activities	679	839	2,282
Plants & Pipelines	19	29	276
Administrative	17	8	5
Total Canada	715	876	2,563
Other International			
Oil and Gas Activities	366	299	217
Plants & Pipelines	139	136	—
Administrative	—	—	1
Total Other International	505	435	218
Worldwide			
Oil and Gas Activities	1,585	1,601	3,082
Plants & Pipelines	163	193	346
Administrative	40	43	26
Total Worldwide	$1,788	$1,837	$3,454

In 2003, worldwide capital expenditures related to oil and gas activities were $1,585 million and included 67 percent associated with development, 19 percent for exploration and 14 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.

Productive Wells

Working interests in productive wells at December 31, 2003 follow.

Year Ended December 31, 2003	Gross	Net
North America		
U.S.		
Crude oil	2,695	1,366
Natural gas	10,990	6,382
Canada		
Crude oil	1,158	521
Natural gas	5,257	4,255
Other International		
Crude oil	120	37
Natural gas	147	56
Worldwide		
Crude oil	3,973	1,924
Natural gas	16,394	10,693
Total Wells	20,367	12,617

Net Wells Drilled

Drilling activity in 2003 was principally in the Western Canadian Sedimentary, San Juan, Onshore Gulf Coast, Ft. Worth, Permian, Anadarko, Wind River and Williston Basins. The following table sets forth the Company's net productive and dry wells.

Year Ended December 31,	2003	2002	2001
North America			
U.S.			
Productive			
Exploratory	0.9	4.5	6.0
Development	399.0	158.6	271.0
Dry			
Exploratory	2.5	6.3	8.5
Development	5.3	2.1	10.1
Total Net Wells—U.S.	407.7	171.5	295.6
Canada			
Productive			
Exploratory	102.5	73.3	22.9
Development	384.4	320.8	158.8
Dry			
Exploratory	48.6	44.7	13.4
Development	57.6	46.2	48.3
Total Net Wells—Canada	593.1	485.0	243.4
Other International			
Productive			
Exploratory	0.7	0.1	2.1
Development	10.9	1.5	5.8
Dry			
Exploratory	1.8	2.0	3.1
Development	1.0	0.1	0.1
Total Net Wells—Other International	14.4	3.7	11.1
Worldwide			
Productive			
Exploratory	104.1	77.9	31.0
Development	794.3	480.9	435.6
Dry			
Exploratory	52.9	53.0	25.0
Development	63.9	48.4	58.5
Total Net Wells—Worldwide	1,015.2	660.2	550.1

As of December 31, 2003, 110 gross wells, representing approximately 73 net wells, were being drilled.

year-end. Average net production in Block 7 for the year was 2.7 MBbls of crude oil per day. In Ecuador, the Company's capital investments in 2003 totaled $42 million.

In Argentina, the Company holds a 25.7 percent working interest in the Sierra Chata concession in the Neuquen Basin. This asset has a net sales capacity of 45 MMCF of natural gas per day from 39 producing wells. During 2003, natural gas sales were curtailed due to low gas prices in Argentina, with the Company's net production averaging only 24 MMCF of natural gas per day. Deferrals of capital programs and a close focus on operating costs have helped mitigate the economic impact of the poor market conditions over the last two years. Market conditions exhibited signs of improvement at year-end 2003.

Elsewhere in South America, the Company entered into an agreement to acquire a 23.9 percent working interest in Peru's Block 90, located 100 kilometers north of the Camisea area in the Ucayali Basin. This block was re-configured from the previously held Block 34/35 concessions. Also in Peru, field geologic studies and a 2-D seismic acquisition program were completed in Block 87 in which the Company holds a 70 percent working interest that could be relinquished in 2004. In Colombia, the Company signed an exploration contract with Ecopetrol for a 100 percent interest in the Orquidea area.

The Company's remaining Northwest European shelf operations consist of non-operated production from the CLAM venture in the Dutch offshore sector. During the second quarter of 2003, the Company acquired the remaining 50% interest in CLAM for a purchase price of approximately $100 million (including cash acquired at closing of $25 million). The CLAM assets yielded an annual production rate of 43 MMCF of natural gas per day in 2003.

North Africa

In North Africa, the Company continued with its exploration and development programs in both Algeria and Egypt. In Algeria, on Block 405a Menzel Lejmat North, in which the Company has a 65 percent working interest, activity was primarily focused on bringing on line the Company-operated MLN central processing facility for crude oil production. Operated crude oil production into the processing plant commenced in July 2003. Net production to the Company in July 2003 was 4.9 MBbls of crude oil per day and increased to 12.4 MBbls of crude oil per day in December 2003. Net annual production from the MLN property averaged 3.9 MBbls of crude oil per day. In December 2003, production from the MLN satellite fields in Block 405a: MLW; MLNW; KMD and MLC commenced, accounting for the higher year-end production. The Company's capital investments in this area in 2003 totaled $71 million.

The Ourhoud Field, in which the Company has a 3.7 percent working interest, produced throughout the year. Some operational difficulties with crude oil export pumps prevented the field from producing at its targeted rate until the final few weeks of the year. During 2003, net production was 4.1 MBbls of crude oil per day.

During early 2003, the final required exploration well in Block 405a, MLSE-8, was drilled. This well was a minor natural gas discovery in shallow zones. However, a subsequent test of deeper horizons for producible hydrocarbons failed to flow. The well has been suspended, pending possible future use in a gas development. Subsequent to drilling the MLSE-8 well, a final relinquishment of non-development areas in Block 405a was submitted to Sonatrach, the Algerian national oil company, and awaits finalization.

In the Akfadou PSC, Block 402d, in which the Company has a 75 percent working interest, seismic interpretation was completed and locations were agreed upon for the two commitment exploration wells required under the contract.

In Egypt, where the Company has a 50 percent non-operated working interest in the Offshore North Sinai permit, an appraisal well, Tao-2, was drilled. The well did not find producible hydrocarbons and was abandoned as a dry hole. Plans continue for the Offshore North Sinai gas project and discussions have continued with the Egyptian authorities on timing and the location for the related onshore facilities for that project.

China

In the Far East, the Company continued its focus on selected basins in China. An offshore oil development project started production in 2003, and an onshore gas development program is in its early phase working toward long-term expansion. The Company is also targeting opportunities to add to its existing leasehold position. The Company invested $44 million in China in 2003.

During the year, fabrication on the Panyu offshore oil development project in the Pearl River Mouth Basin of the South China Sea was completed with installation and commissioning of all components. 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 production rapidly increased thereafter. In December 2003, the average net production was 11.1 MBbls of crude oil per day, with net production for the year of 1.2 MBbls of crude oil per day.

The Company holds a 100 percent working interest in the onshore Chuanzhong Block in the Sichuan Basin, a natural gas project currently at the end of the appraisal phase. 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. Three appraisal wells were drilled in 2003 and completion of the appraisal program and initiation of development is expected to occur in 2004. During 2003, net production in this area was 4 MMCF of natural gas per day.

South America

The Company's efforts in South America during 2003 focused on expanding near-term production potential and enhancing long-term exploration opportunities. Net production from South America averaged 2.8 MBbls of crude oil per day and 24 MMCF of natural gas per day. The Company invested $43 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 I development of the Yuralpa Field in Block 21 was completed with first production achieved during December 2003. One development well was successfully drilled in Block 7 during 2003. The Oso well was deepened to an untested target, which resulted in a new field discovery in the Hollin formation. Testing of the well was ongoing at

The O'Chiese and Whitecourt areas in central Alberta yielded 2003 production of 226 MMCF of natural gas per day, 8.9 MBbls of NGLs per day and 2.7 MBbls of crude oil per day. The O'Chiese and Whitecourt areas were the focus of a $156 million exploration and development program in 2003 that mostly targeted the Lower Cretaceous and Jurassic sands, the principal historical targets. A total of 168 wells were drilled, including 26 wells in shallow gas formations.

The Company continued exploration and development activities in the greater Ring Border area on the border of northern Alberta and British Columbia. Production in this area during 2003 averaged 111 MMCF of natural gas per day and 1.9 MBbls of NGLs per day. A capital program in this area of $72 million targeted the Bluesky, Gething and Montney formations and 101 wells were drilled. This included 19 wells that extended the Gutah discovery west of the Ring Border Unit. The Kahntah Field, lying northwest of the Ring Border Field, was also brought on-stream to the existing Ring Border plant.

In the Kaybob area, production for the year averaged 69 MMCF of natural gas per day and 0.7 MBbls of NGLs per day. This represents production growth of 54 percent over 2002. During 2003, the Company invested $78 million, drilled 59 wells in the Lower Cretaceous formation and expanded the wholly owned Berland River gas processing plant.

The Viking Kinsella property produced approximately 87 MMCF of natural gas per day in 2003, a 42 percent increase over 2002. An additional 79 wells were drilled on the property in 2003. The infrastructure was expanded with the purchase of a gas processing plant at Scoville Lake and the construction of a new gas processing plant at Vernon Lake.

Mackenzie Delta

In the MacKenzie Delta, a successful exploration well was drilled at the Langley K-30 location resulting in a discovery from the Eocene Taglu formation.

Other International

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

Year Ended December 31, 2003	**Worldwide**	**Other International**	**% of Worldwide**
		($ In Millions)	
Oil and gas capital expenditures			
Development	$1,056	$232	22%
Exploration	301	35	12
Acquisitions — proved	228	99	44
Total oil and gas capital expenditures	$1,585	$366	23%
Production			
Natural gas (MMCF per day)	1,899	167	8%
NGLs (MBbls per day)	64.8	—	—
Crude oil (MBbls per day)	46.5	12.1	26%
December 31, 2003			
Proved reserves (TCFE)	11.8	1.4	12%

Northwest Europe

Operations in Northwest Europe provided the majority of the Company's production outside of North America during 2003, from assets in the East Irish Sea and in the Dutch sector of the North Sea.

The East Irish Sea assets consist of eight licenses covering 249,000 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. A new sub-sea well was completed during mid-2003, bringing the total number of producing wells in the Millom and Dalton Fields to nine. Net production from the East Irish Sea averaged 96 MMCF of natural gas per day during 2003. The Company invested $218 million of capital in this area, including $108 million of oil and gas capital.

In 2003, the development of the sour gas fields in the East Irish Sea continued with first production planned by mid-2004. During 2003, three production wells were completed from the offshore platform and tested at a combined rate of over 180 MMCF of natural gas per day. The pipeline transporting gas from these offshore facilities was also completed during 2003 and construction work continued on the new onshore terminal that will process the sour gas prior to sale.

The Company continued its highly active waterflood development program at the Cedar Hills Unit by drilling 24 wells, extending 33 existing horizontal wells, and increasing water injection volumes. Seven of these newly drilled wells are testing 160-acre infill spacing. This spacing is also being pilot tested in East Lookout Butte and was expanded in 2003 with the addition of 11 wells. These pilots are being monitored to further assess the feasibility of infill drilling on 160-acre spacing to improve the efficiency of the waterflood.

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 2003 from the Anadarko Basin averaged 78 MMCF of natural gas per day and 0.4 MBbls of NGLs per day. During 2003, the Company invested $27 million in the Anadarko Basin. Operated activity focused on the Red Fork formation in Roger Mills County, Oklahoma where the Company drilled 19 wells.

Permian Basin

Permian Basin operations, in west Texas, are focused on the Waddell Ranch Field. Total Permian Basin production in 2003 averaged 15 MMCF of natural gas per day, 3.5 MBbls of crude oil per day and 1.6 MBbls of NGLs per day, with the Waddell Ranch Field contributing 11 MMCF of natural gas per day, 2.8 MBbls of crude oil per day and 1.6 MBbls of NGLs per day. During 2003, the Company invested $9 million in Permian Basin operations.

Fort Worth Basin

The Fort Worth Basin of north central Texas had a significant increase in activity in 2003 for the Company following the 2002 acquisition of a largely undeveloped Barnett Shale formation acreage position in Denton County, Texas. Net volumes increased from 18 MMCF of natural gas per day, 0.3 MBbls of NGLs per day and 0.3 MBbls of crude oil per day at the beginning of the year to 34 MMCF of natural gas per day, 4.1 MBbls of NGLs per day and 1.1 MBbls of crude oil per day at year end. The Company employed up to nine rigs during the year to drill 163 wells in the Barnett Shale formation including a two-well pilot program to test horizontal well technology. The Company invested $90 million in 2003 with production averaging 28 MMCF of natural gas per day, 2.1 MBbls of NGLs per day and 0.7 MBbls of crude oil per day.

Onshore Gulf Coast

The Onshore Gulf Coast includes a number of drilling trends in south Louisiana, as well as 660,000 acres of fee lands where the Company owns the mineral rights and surface lands. In 2003, the Company invested $75 million in 52 drilling, workover and facilities projects in south Louisiana. Net production for 2003 averaged 94 MMCF of natural gas per day, 6.6 MBbls of crude oil per day and 1.2 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, as well as frontier exploration in the Mackenzie Delta in the Northwest Territories.

Canadian activity in 2003 focused on production growth, reserve additions and cost control on the integrated assets acquired since 1999 by expanding original activity into large-scale repeatable drilling programs in conventional and lower permeability reservoirs. Oil and gas capital investment in Canada was $679 million, including acquisitions, and resulted in the completion of 737 gross wells.

The Deep Basin area, in Alberta and British Columbia, consists of the Elmworth, Wapiti, Noel and Brassey Fields. The Company acquired interests in 84,000 acres of mineral rights through Crown Land sales in Alberta and British Columbia. This included approximately 40,000 acres in the Brassey area to extend drilling activity in the tight gas trend. In 2003, a $256 million oil and gas capital program was focused on exploration and development in the Deep Basin area. As a result, 180 wells were drilled and 233 MMCF of natural gas per day and 15.6 MBbls of NGLs per day were produced from this area, representing a 12 percent increase year over year.

In the Deep Basin, the 2003 program focused on continued exploitation of tight gas reservoirs in the Cadomin and Chinook formations. Regulatory approval to reduce well spacing in the Cadomin from 640-acres to 320-acres was expanded from a 33-section area at the start of the year to 83 sections, with an additional 32 sections pending final regulatory approval. As a result of the down-spacing approvals, the Company drilled 28 infill wells in the Cadomin formation in the Elmworth area and 19 infill wells in the Chinook formation.

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 7,300 well completions in the San Juan Basin and holds interests in an additional 4,300 non-operated well completions.

In 2003, the Company invested $115 million in oil and gas capital, excluding acquisitions, that included 322 new wells and approximately 585 workovers of existing wells. The Company's net production from the San Juan Basin averaged approximately 546 MMCF of natural gas per day, 31.3 MBbls of NGLs per day and 1.2 MBbls of crude oil per day during 2003. 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. 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 also developed 35 BCFE of additional Fruitland Coal reserves by drilling new wells on 320-acre and 160-acre spacing, and added 34 BCFE of proved undeveloped reserves. In 2003, net production from the Fruitland Coal averaged 199 MMCF of natural gas per day from over 1,700 completions.

In 2003, the New Mexico Oil and Gas Conservation Division (NMOCD) granted approval to allow infill drilling on 160-acre spacing in the high-productivity portion of the Fruitland Coal pool. The approval by the NMOCD made available many drilling opportunities that are expected to result in additional production and reserves in San Juan.

Also in 2003, the Company repurchased three production interests in properties related to coalbed methane production. These repurchases added net annualized volumes of 79 MMCF of natural gas per day and 95 BCFE of reserves at a price of approximately $80 million, yielding an average acquisition cost of about $0.84 per MCFE.

The three conventional formations (Mesaverde, Pictured Cliffs and Dakota), located 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 2003, the Company continued its ongoing infill drilling program in this formation by developing 115 BCFE of reserves. In the Dakota formation, the Company developed 40 BCFE of additional reserves by drilling new wells on 160-acre and 80-acre spacing during 2003 and added 274 BCFE of proved undeveloped reserves. Net production from the tight gas producing formations averaged 347 MMCF of natural gas per day and 31.3 MBbls of NGLs per day.

During the year, the Company continued its cost management efforts in the San Juan Basin. Year-over-year, net operated capital costs for like-kind projects were essentially flat to 2002 as a result of a variety of process improvements. Similarly, lease operating expenses were reduced by $1.5 million from 2002, despite inflationary and operational cost pressures, resulting in unit costs per MCFE being essentially flat to 2002. This was achieved primarily through compression optimization and cost savings for produced water disposal.

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 88 MMCF of natural gas per day in 2003 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 2003 totaled $19 million for approximately 56 newly drilled wells and workover projects in the deep Madison and shallower formations. During the summer of 2003, the Company elected to shut-in natural gas production from the deep Madison wells after localized pipe deformations were found during inspection of the field's high-pressure gathering system. By year end, the Company had completed repairs on four gathering lines, largely restoring production. Two other gathering lines are producing at reduced rates pending further repairs scheduled for mid-2004. In addition, the final gathering line is also expected to be completed at that time. The Company spent $4 million for repairs to the deep Madison gathering system in 2003. The Big Horn #9-4, the last of the planned deep development wells, began producing in mid-November 2003. The Company owns an approximate 50 percent working interest in the Lost Cabin Gas Plant and a 42 percent net revenue interest in the Madison reservoir.

Williston Basin

The Williston Basin operations, in western North Dakota and eastern Montana, are primarily focused on the Cedar Creek Anticline. Total Williston Basin production averaged 13 MBbls of crude oil per day and 4 MMCF of natural gas per day. During 2003, the Company invested $66 million on horizontal drilling and workover projects, primarily located in the Cedar Hills South and East Lookout Butte waterflood units.

PART I

ITEMS ONE AND TWO

BUSINESS AND PROPERTIES

Burlington Resources Inc. (BR) is a holding company engaged, through its principal subsidiaries, 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), in the exploration for and the development, production and marketing of natural gas, crude oil and NGLs. BR ranks 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.

In October 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its asset portfolio, primarily in the U.S. During 2002, the Company sold approximately 1 TCFE of reserves and the Val Verde Plant. 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. This acquisition was funded with cash on hand and proceeds from the issuance of $1.5 billion of fixed-rate notes and $400 million of commercial paper. The transaction was accounted for under the purchase method.

The Hunter acquisition added a portfolio of producing 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, North America's third-largest natural gas field, with approximately 1.5 million gross acres and 17 major producing horizons. The acquisition added estimated proved reserves of 1.3 TCFE along with approximately two million net undeveloped acres.

In November 1999, BR consummated the acquisition of Poco Petroleums Ltd. valued at approximately $2.5 billion. The transaction was funded through the issuance of 38,393,135 shares of the Company's Common Stock and was accounted for under the pooling of interests method.

The Company's reportable segments are U.S., Canada and Other 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 the Arctic coast of Canada. The Company's North American operations include a mix of production, development and exploration assets.

Year Ended December 31, 2003	Worldwide	U.S.	% of Worldwide	Canada	% of Worldwide
			($ In Millions)		
Oil and gas capital expenditures					
Development	$1,056	$378	36%	$446	42%
Exploration	301	52	17	214	71
Acquisitions — proved	228	110	48	19	8
Total oil and gas capital expenditures	$1,585	$540	34%	$679	43%
Production					
Natural gas (MMCF per day)	1,899	865	46%	867	46%
NGLs (MBbls per day)	64.8	37.4	58	27.4	42
Crude oil (MBbls per day)	46.5	29.3	63%	5.1	11%
December 31, 2003					
Proved reserves (TCFE)	11.8	7.6	64%	2.8	24%

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.

Production and processing includes direct and indirect expenses, including divisional office expenses, incurred to manage, operate and maintain the Company's wells and related equipment and facilities.

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 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 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).

Reserve replacement costs are 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.

Reserve replacement ratio is calculated by dividing the sum of reserve revisions, extensions, discoveries and other additions and acquisitions by the actual production for the corresponding period.

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 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.

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.

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.

Below are certain definitions of key 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 strata 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.

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.

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

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, 2003

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, 2004 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 30, 2004: $10,829,196,847 and as of June 30, 2003: $10,852,397,432.

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 30, 2004, Shares Outstanding: 197,829,683

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.

Form 10-K Contents

BURLINGTON RESOURCES

Burlington Resources Inc.
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Houston, Texas 77002
(713) 624-9500
www.br-inc.com

BURLINGTON RESOURCES 2003 ANNUAL REPORT FORM 10-K

CONTINUING

RESULTS

BURLINGTON RESOURCES

2003