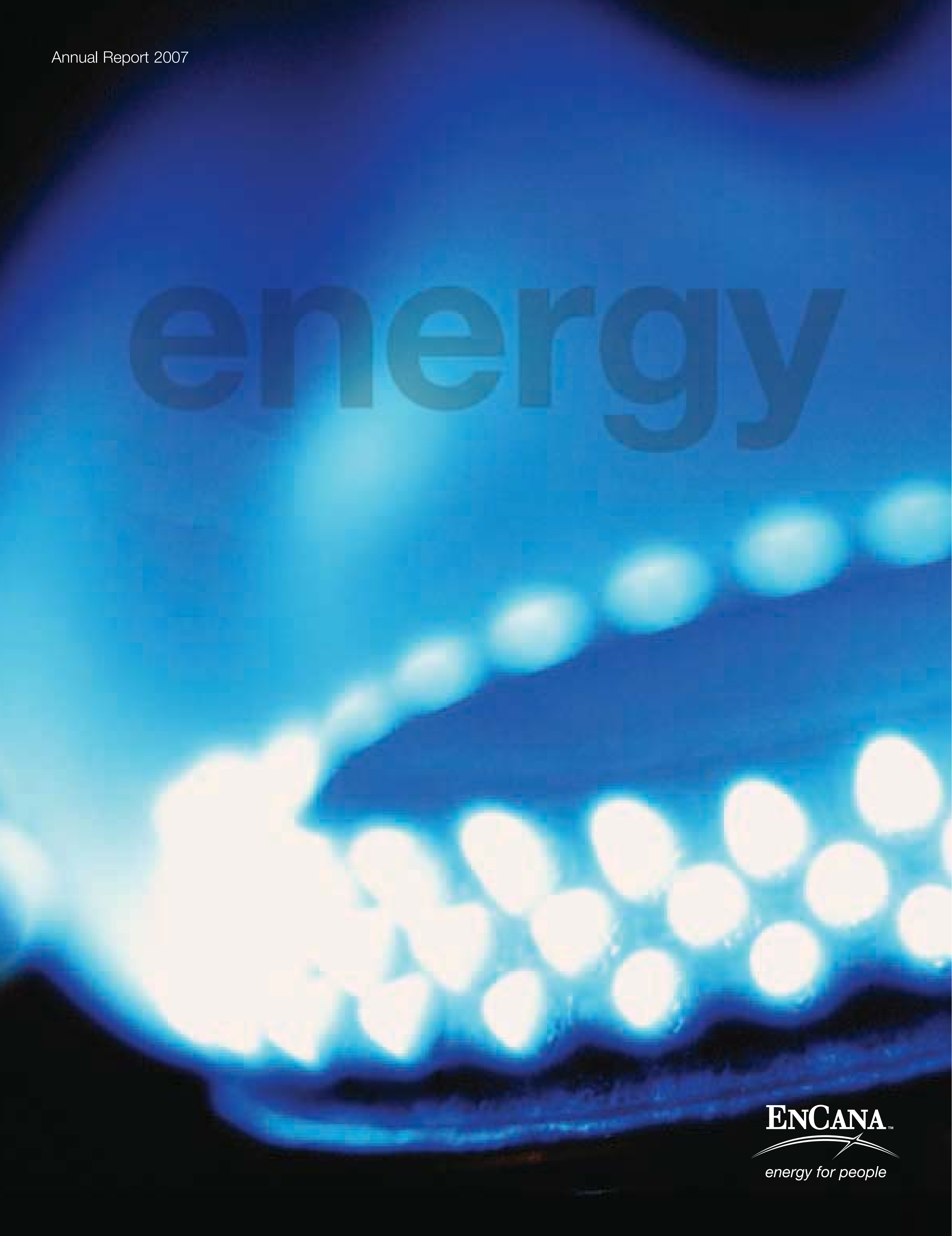
Annual Report 2007



EnCana

energy for people

Energy for people

As a leading North American energy company, headquartered in Calgary, Alberta, we strive to be a trusted contributor in the communities where we work and live. We continuously work to ensure our business is conducted in an ethical and socially responsible manner – a manner in which safe work practices and our approach to the environment are priorities.

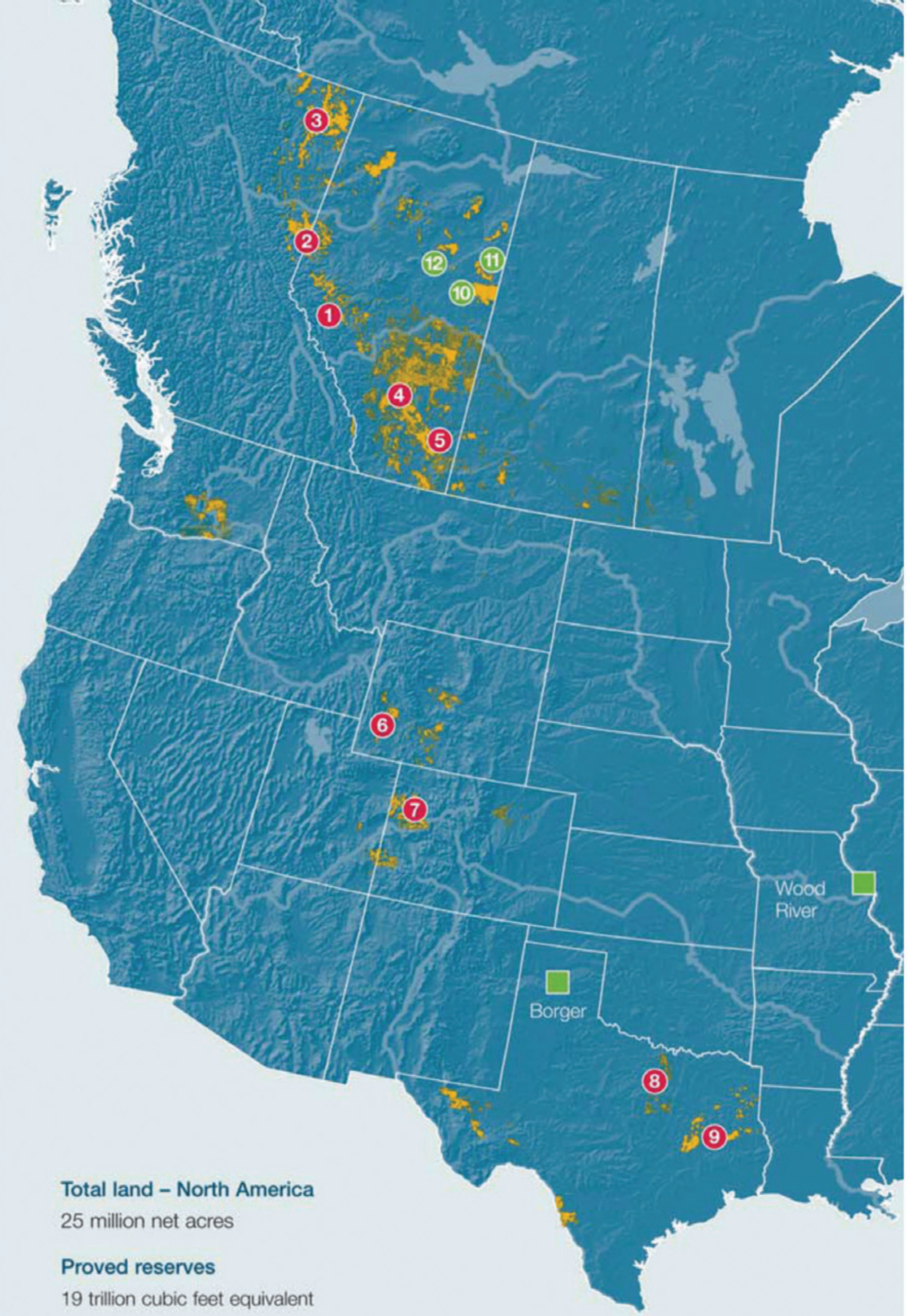
We produce approximately 4.4 billion cubic feet of gas equivalent per day. More than 80 percent is natural gas – the cleanest burning of all fossil fuels. We are also a technical and cost leader in the in-situ recovery of bitumen through steam-assisted gravity drainage (SAGD) – production that is integrated with our two refineries in the United States.

Natural gas and oil resource plays* are our strategic focus. With 12 key resource plays across Canada and the United States we are able to invest for the long term and apply continuous improvements to all areas of our business:

- leveraging technical innovations
- acting on the feedback we get from our stakeholders
- improving energy efficiencies in our day-to-day operations and processes

That strategic focus, combined with the ingenuity, technical leadership and enthusiasm of our 7,250 employees and contractors across Canada and the United States, enables us to deliver on our mission of providing energy for people across North America.

*__Resource plays:__ large continuous accumulations of hydrocarbons capable of delivering steady, reliable production growth for decades.



Total land – North America
25 million net acres

Proved reserves
19 trillion cubic feet equivalent

Well inventory
37,000 locations

Our key resource plays

Natural gas

1. Bighorn
2. Cutbank Ridge
3. Greater Sierra
4. CBM
5. Shallow Gas
6. Jonah
7. Piceance
8. Fort Worth
9. East Texas

Oil

10. Foster Creek
11. Christina Lake
12. Pelican Lake

Refineries

EnCana land

Detailed descriptions of our key resource plays can be found on www.encana.com.

Highlights

Financial

US$ millions, except per share amounts	2007	2006	% Change
Revenues, Net of Royalties	**21,446**	16,399	31
Cash Flow (1)	**8,453**	7,161	18
Per Share – Diluted	**11.06**	8.56	29
Net Earnings	**3,959**	5,652	(30)
Per Share – Diluted	**5.18**	6.76	(23)
Operating Earnings (1)	**4,100**	3,271	25
Per Share – Diluted	**5.36**	3.91	37
Capital from Continuing Operations	**6,035**	6,269	
Shares Purchased (millions of shares) (2)	**38.9**	85.6	
Average Price	**52.05**	49.26	
Net Debt to Capitalization (%)	**34**	27	
Net Debt to Adjusted EBITDA (times) (1)	**1.2**	0.6	
Net Debt to Proved Developed Reserves ($/Mcfe)	**1.05**	0.67	
Dividend Yield (%) (3)	**1.2**	0.8	

(1) Non-GAAP measures as referenced in the Advisory on page 63.
(2) Shares purchased under Normal Course Issuer Bid.
(3) Based on NYSE closing share price at year end.

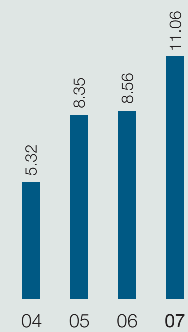
Operating

After royalties	2007	2006	% Change
Continuing Operations – North America			
Natural Gas (MMcf/d)			
Canada	**2,221**	2,185	2
U.S.	**1,345**	1,182	14
Total Natural Gas (MMcf/d)	**3,566**	3,367	6
Oil & NGLs (bbls/d)			
Foster Creek & Christina Lake (1)	**26,814**	21,384	25
North America, Other	**107,340**	114,505	(6)
Total Oil & NGLs (bbls/d) (1)	**134,154**	135,889	(1)
Total Production from Continuing Operations (MMcfe/d) (1)	**4,371**	4,182	5
Discontinued Operations			
Ecuador (bbls/d)	**–**	11,996	
Total Production from Discontinued Operations (MMcfe/d)	**–**	72	
Total Production (MMcfe/d) (1)	**4,371**	4,254	3
Refinery Operations (2)			
Crude Oil Capacity (Mbbls/d)	**452**	–	
Crude Oil Runs (Mbbls/d)	**432**	–	
Reserves (3)			
Year-End Reserves (Bcfe) (4)	**18,863**	19,218	(2)
Net Reserves Additions (Bcfe)	**3,629**	2,311	57
Production Replacement (%)	**227**	144	
Finding & Development Cost ($/Mcfe)	**1.65**	1.99	
Recycle Ratio	**3.5**	2.7	
Reserve Life Index (years)	**11.8**	12.0	

(1) 2006 figures represent 50% of Foster Creek and Christina Lake.
(2) Represents 100% of the Wood River and Borger refinery operations.
(3) Based on proved reserves only.
(4) After adjusting for oil integration, year-over-year reserves grew 12%.

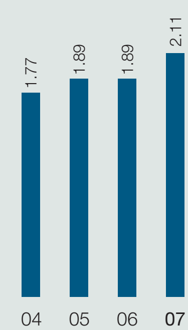
Cash flow per share

($/share)



Production per share*

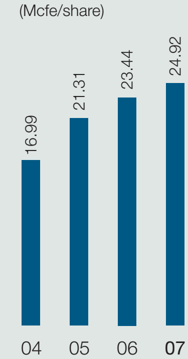
(Mcfe/share)



*Represents 50% of Foster Creek and Christina Lake.

Reserves per share

(Mcfe/share)



Why own EnCana?

With the predictability, stability and visible growth of our resource play strategy, EnCana represents a unique investment opportunity. Our business decisions are based on unlocking the value in the company's unconventional assets, improving capital efficiency and decreasing the risk exposure of our portfolio.

Maximize total shareholder return

Focus on creating sustainable value for shareholders

Develop unparalleled asset base; unlock underlying value

- Sustainable production growth – target 5 percent per year
- 25 million net acres in North America
- 18.9 trillion cubic feet equivalent proved reserves
- Approximately 10-year drilling inventory identified on existing developed lands

Exercise financial discipline and flexibility; respond to market conditions

- Strong balance sheet
- Net debt to capitalization of 34 percent
- Net debt to adjusted EBITDA of 1.2 times
- Robust project returns – target risk-adjusted internal rate of return greater than 15 percent, after tax

Return value to shareholders; pay dividends and purchase shares

- Minimum 10 percent free cash flow target
- Free cash flow supports a growing dividend and share purchase program
  - Doubled dividend in 2007 and 2008
  - Purchased about 270 million shares since 2002

Advisory Certain information regarding the Company and its subsidiaries set forth in this document, including management's assessment of the Company's future plans and operations, may constitute "forward-looking statements" or forward-looking information under applicable securities laws and necessarily involve risks and uncertainties associated with future events. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements or information. For further details see the Advisory on page 61 of this report.

For convenience, references in this document to "EnCana", the "Company", the "company", "we", "us", "our" and similar references may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (each a "Subsidiary" or, if more than one, "Subsidiaries") and the assets, activities and initiatives thereof. References to financial results of operations refer to the consolidated financial results of EnCana Corporation and its Subsidiaries, taken as a whole, except where otherwise noted or the context otherwise implies.

This document contains references to measures commonly referred to as non-GAAP measures. Additional disclosure relating to these measures is set forth in the Advisory.

References to pro forma integrated oil production growth from 2006 volumes reflect the transaction with ConocoPhillips.

Did you know?

Oil and natural gas products are essential to our everyday lives. We use them to cook our food, heat and cool our homes and fuel our vehicles. But did you know that oil and gas derivatives are also used to make plastics, steel and asphalt? Without them we wouldn't have cars, computers, countless household items such as pots and pans, or the hundreds of other items we use daily.

Did you know?

Natural gas, which is the cleanest burning fossil fuel, accounts for more than 80 percent of EnCana's production. According to the Alberta Department of Energy, the amount of greenhouse gas released from natural gas is significantly lower than emissions from wood, coal and oil. When natural gas replaces these other fuels, emissions of greenhouse gases are reduced as much as 50 percent.

CEO's message

2007 – a year that clearly illustrates the sustainable value-creation capacity of our disciplined North American resource play strategy.

Randy Eresman
President & Chief Executive Officer

EnCana achieved remarkable operational, financial and strategic performance in 2007 – a year when we met or exceeded our targets for production growth, cash flow and capital discipline, and a year that I believe clearly illustrates the sustainable value-creation capacity of our disciplined North American resource play strategy.

2007 marked our first full year focusing exclusively on North American unconventional natural gas and integrated oil resource development. We sharpened our investment and operating discipline by moderating our growth forecast and capital investment to a level that delivered stronger returns. It was also the inaugural year of our integrated oil business, linking our leading steam-assisted gravity drainage (SAGD) oil projects with downstream upgrading and refining. This sustainable business venture lowers the development and marketing risk for our enormous bitumen resources and defines a clear long-term development path to deliver this oil to market. These initiatives set the stage for our strong results – performance that was reflected in our 2007 share price.

During the year, EnCana shares delivered a total return of 27 percent on the TSX in Canadian dollars, while shares on the New York Stock Exchange delivered a total return of 50 percent in U.S. dollars.

Our North American resource play strategy offers shareholders an investment vehicle that targets to maximize returns by sustaining production growth of about 5 percent per year, maintaining the financial discipline to respond to market conditions and generating a minimum of 10 percent free cash flow that augments value through share purchases and increasing dividends. We capture large early life unconventional resources. We rigorously seek technical and commercial solutions to enhance their value and we use a manufacturing approach for their development. Throughout the entire process we manage operational, financial and reputational risks. All that came together in 2007, a year when our teams executed with excellence.

Natural gas growth per share averages 15 percent

Our 2007 natural gas production growth per share averaged 15 percent, driven by a year-over-year growth of 14 percent from our key resource plays across North America, including 44 percent growth at East Texas (home to the prolific Amoruso field tapping the Deep Bossier formation), 38 percent growth at Cutbank Ridge in British Columbia and 20 percent growth at Jonah in Wyoming. Production from our integrated oil projects at Foster Creek and Christina Lake grew 25 percent on a pro forma basis. Total gas and pro forma oil production increased 11 percent per share.

Our financial performance reflected our strategic initiatives and our field achievements, with cash flow per share up 29 percent to $11.06, or $8.5 billion, and operating earnings per share up 37 percent to $5.36, or $4.1 billion. Strong refining margins through much of 2007 helped generate $1.1 billion of operating cash flow from our integrated oil downstream business.

Capital investment was down 4 percent from 2006 to $6 billion and we generated $2.4 billion of free cash flow. Underpinning our capital investment were risk management measures – a hedging program that delivered cash flow about $1.1 billion higher than it would have been at market natural gas prices. Although 2007 benchmark natural gas prices decreased 5 percent, our realized gas prices increased 7 percent due to our hedging program. Our 2007 proved reserves additions were also strong – 227 percent of production and at a highly competitive finding and development cost of $1.65 per thousand cubic feet equivalent. These strong proved reserves additions, and a major gas acquisition in Texas, continued to build the strength of our natural gas assets across North America.

Dividend doubled, again

As a reflection of our increased confidence in the sustainability of our resource play strategy and our unconventional assets, we doubled our dividend two years in a row, first in March 2007 and again this March. Now at $1.60 per share annually, our dividend yield is about 2.1 percent based on the March 6 NYSE share price of $77.50, which ranks it among the leaders of both our integrated and upstream peers.

While we are predominantly focused on North America gas, our operations are diversified across the continent, located in most of the major and emerging production basins. This diversification reduces operating risk in our portfolio and exposes us to opportunities created by ourselves and by others. EnCana's goal is not to be the biggest. It is about having the best asset quality.

Capturing unconventional value deep in Texas

Over the past two years in East Texas, EnCana led the exploration, definition and systematic development of the exciting new Amoruso field, tapping the Deep Bossier gas formation. Late in 2007, we bought our partner's remaining half of this promising play for $2.55 billion. Deep Bossier wells can flow at enormous rates; one of our recent wells flowed as high as 65 million cubic feet of gas during initial production testing. In the two years since we entered the play in mid-2005, Amoruso production has grown from zero to more than 215 million gross cubic feet per day. Amoruso is an exciting long-life asset that is at the earliest days of development in the heart of the Texas gas region, close to well-developed processing and transportation infrastructure and highly liquid gas markets that yield some of the strongest field netbacks in North America. East Texas has the potential to become the leading resource play in our North American portfolio.

Integrated oil benefits clearly illustrated during inaugural year of operations

Our upstream SAGD oil production at Foster Creek and Christina Lake grew 25 percent, on a pro forma basis, to about 26,800 barrels per day in 2007. Construction of additional phases is underway and production in 2008 is expected to grow about 25 percent to average about 34,000 barrels per day. Downstream, our partner ConocoPhillips completed the installation of a new 25,000 barrel-per-day coker at the Borger Refinery, enabling the upgrading of Canadian bitumen. At the Wood River Refinery, engineering and regulatory work continues this year to expand future bitumen upgrading capacity. EnCana's new refining interests generated strong cash flow as refining margins tracked well above historical levels through the middle of 2007. This helped our integrated oil business generate about $1.3 billion in operating cash flow, approximately double the company's initial forecast at the start of 2007. The value of our integrated oil business became clearly evident in its first year of operations.

2008 aimed at U.S. natural gas and integrated oil growth

Our land base of 25 million net acres contains approximately 10 years of drilling opportunities within most of the major and emerging producing basins in North America. This abundant and diverse portfolio of organic growth opportunities provides EnCana with the flexibility to reduce risk by redirecting investment to the most attractive locations. With the geological and economic success in our unconventional gas fields, Jonah in Wyoming and Amoruso in East Texas, we are substantially increasing investment

25
percent

We are advancing development of longer term projects such as our SAGD production, which is expected to grow about 25 percent this year.

in our U.S. natural gas production, which is expected to grow by about 25 percent in 2008. We are also advancing development of longer term projects such as our SAGD oil production, which is also expected to grow by about 25 per cent this year, and are progressing expansions of our bitumen refining capacity downstream to accommodate future growth. Add to that the advancement of the Deep Panuke gas project offshore Nova Scotia, which is expected to deliver first gas late 2010. The future growth potential for EnCana is identifiable and reliable.

While the diverse character of our North American geological portfolio offers multiple attractive opportunities, we have reduced our activity in Western Canada, particularly on Crown lands in Alberta. The cumulative effects of increasing Alberta royalties, property taxes and labour costs, plus the strengthening Canadian dollar, have substantially eroded the returns on some of our new and emerging resource plays compared to other opportunities in our portfolio. Consequently, we have temporarily reduced some drilling activity in Western Canada until economic conditions improve. Over the longer term, we believe that the energy industry and the Government of Alberta will need to work together to re-establish the competitiveness of the development of Alberta's significant new and emerging resources.

In 2008, we expect to grow natural gas production by about 6 percent, while oil and natural gas liquids production is expected to decrease slightly, resulting in a total production increase of about 5 percent to about 4.6 billion cubic feet equivalent per day. EnCana expects to fund 2008 capital investment with internally generated cash flow and deliver at least 10 percent free cash flow, which is underpinned by natural gas hedges on about half of our forecasted gas production and our ongoing program of non-core asset divestitures.

Reliable, sustainable value creation for shareholders, reliable energy for people

We continue to focus on a moderate, sustainable pace of growth, capital discipline and the return of cash to shareholders through an ongoing program of share purchases and increasing dividends. This is our strategy. This is our business. This is our culture at EnCana, a company founded on sound principles of responsible operation. Acting in a conscientious and reliable manner is as important to sustaining our business as finding new energy resources. Throughout our 2007 Annual Report, you will see photos and facts connecting the technology and innovation deployed in our reservoirs and refineries to the delivery of reliable clean-burning natural gas and gasoline to people's homes, vehicles and workplaces. We are working to build a company that can be relied upon in all we do, in all the goals we set, in all the commitments we undertake. We are focused on creating sustainable value for our shareholders as we pursue our mission – energy for people. Integral to this, we contribute favourable, long-lasting benefits for those who live and work in the communities where we also live and operate, and we continually look for ways to reduce our impact on our environment.

As an independent measure of our performance, EnCana was listed on the 2007 Dow Jones Sustainability World and North American indices (DJSI). Companies on the DJSI World represent the leading 10 percent in terms of compliance with social and environmental principles for sustainable development. While we are proud of this recognition and inclusion in this leadership group, we know we have more to do. Building a sustainable company requires continuous effort, and that's our endless focus and pursuit.

On behalf of EnCana's executive team, I want to thank our Board of Directors for its unwavering vision and sound guidance in establishing EnCana as a leader in unconventional gas and integrated oil development. In addition, on behalf of EnCana's leadership team, I want to thank our employees and contractors for a remarkable year of excellent execution and value creation.

Randy Eresman
President & Chief Executive Officer
March 6, 2008

Did you know?

As North America's largest natural gas producer, EnCana's 45,000 wells supplied about 6 percent of Canadian and United States natural gas consumption.

Natural gas

Unconventional* natural gas is expected to be the most significant source of North American production growth – most of our natural gas production is unconventional.

Unconventional natural gas is our focus accounting for approximately 88 percent of our total natural gas production. In 2007, we produced 3.6 billion cubic feet of natural gas per day from approximately 45,000 wells across North America. Production from our nine key gas resource plays represented about 76 percent of our total gas production. Much of our 6 percent natural gas growth in 2007 came from our Cutbank Ridge, CBM and Bighorn resource plays in Canada, and East Texas, Fort Worth and Jonah resource plays in the United States.

A unique feature of EnCana's resource play approach is that our asset teams are continuously making small improvements they then apply to the entire field and, in many cases, across our operations. We identify and apply the most effective technology to our resource plays to increase the amount of gas we recover as we drive down costs over time. As a result, this manufacturing methodology generates small improvements that add up – with benefits ranging from increases in production to efficiency gains and enhanced safety.

The Deep Bossier trend (part of our East Texas resource play), the Jonah field in Wyoming, and the Montney formation (part of our Cutbank Ridge resource play in British Columbia) played key roles in our success last year – in large part due to the successful application of continuous improvements by the asset teams as discussed below.

The strength of the Deep Bossier

Two of the five most prolific wells drilled onshore in the United States in the last five years produce from the Deep Bossier formation in Texas.

EnCana has been active in Texas since 2004. Texas has significant gas resources and well-established regulatory processes, close proximity to markets, and a strong base of experienced service providers.

In November 2007, we expanded our East Texas holdings when we acquired the natural gas and land interests of our Texas-based partner – which included the Amoruso field. Adding to our existing 50 percent stake, the transaction gives us 100 percent ownership of one of the fastest growing and highest potential natural gas fields in North America. As operator of the field since our entry in 2005, we have led the exploration, definition and systematic development of this prolific new geological resource. From our start in 2005 to the end of 2007, the production from the Amoruso field has grown from zero to more than 215 million gross cubic feet per day. We estimate these lands have about 370 net well locations.

The field holds tremendous growth potential in the near and longer term and is among the best new unconventional gas properties in North America. In fact, two of the five most prolific wells drilled onshore in the last five years in the United States produce from the Deep Bossier formation.

As with all our operations, efficiency is a priority in the development of the high-productivity wells in East Texas. In early 2007, we undertook a streamlining initiative for our drilling and completions process resulting in an 8 percent reduction of our well costs within a one-year period. Specialized safety training is both mandatory and ongoing for all employees and contractors operating in and around these high-temperature, high-pressure wells.

Using the subsurface model to optimize results in East Texas

Our efforts in 2007 were focused on delineating the field and acquiring 3-D seismic. The log and seismic data, together with well performance, have helped us develop a subsurface model that we can use to identify and optimize future well locations. The growing production in the Deep Bossier trend demonstrates how knowledge gained from our experience in the Amoruso field and the application of innovative technology can produce tangible results. This additional information influenced our decision to increase our working interest in the field – an acquisition that has further strengthened our unconventional asset base and our demonstrated competitive advantage in North American resource plays.

***Unconventional:** a term that refers to the unique characteristics of reservoirs that require the application of advanced technology to extract the resources.

Prolific Jonah field

EnCana entered the Jonah field in southwest Wyoming in 2000, having purchased the asset from a private company. The field houses a tremendous resource base with original gas in place estimated to be approximately 400 billion cubic feet per section. We drill about 150 wells each year, with production having risen from about 100 million cubic feet per day in 2001 to a forecast of almost 600 million cubic feet per day in 2008.

As with many of our resource plays, Jonah's size allows us to pilot technology, make incremental improvements throughout our development process to enhance value, and apply what we learn to future wells.

In 2007 we substantially increased production from our wells by changing our fracing* fluid to a type that was identified when we piloted new completion techniques. Other innovations at Jonah include portable flowback test units that cut flaring and enable gas production during fracing operations, which increases sales and reduces emissions. We also employ wooden mats to minimize surface impact on sagebrush and other native plants on drilling sites.

Jonah field – making the most of our culture of innovation

Because the field is close to the Wind River mountain range – an environment that requires the highest level of protection under the U.S. Clean Air Act – environmental approvals received in March 2006 indicated we had to either limit our activity or develop technologies that kept emissions to a minimum.

The Jonah operations team evaluated a number of solutions and determined that the best way to reduce emissions was to replace traditional diesel engines with natural gas-powered rigs.

Jonah now has nine natural gas-powered rigs in its fleet. Switching to natural gas has also resulted in substantial cost savings. We estimate saving about $1 million per rig per year in fuel along with a significant reduction in emissions.

560
MMcf/d

In 2007, we produced approximately 560 million cubic feet of gas per day from about 730 wells in the Jonah field.

***Fracing or fracturing:** a process used to break the formation rock and stimulate gas production from underground hydrocarbon bearing reserves.

5.8
fracs

There were on average 5.8 fracs per horizontal well in the Montney formation in 2007.

Horizontal well technology enhances performance in the Montney formation of Cutbank Ridge

We have been building our operations in and around the Bissette area in northeastern British Columbia, for the past decade. Two years ago, within the Cutbank Ridge resource play, we sharpened our focus on the Montney formation. With improved technology, we have increased Montney production from 10 million to 100 million cubic feet of gas per day. We have a significant land position – about 250,000 acres in the core of the play – and have leveraged the knowledge and skills of our employees and contractors to achieve increased operational efficiency through horizontal well technology. This technology employs longer-reaching wells, each with an increased number of fracs, and is at the forefront of the industry. Where once we could complete four fracs per well, we now complete as many as eight. Each horizontal well frac acts like and replaces a vertical well, substantially reducing the number of drilling locations and the surface area of our operations. We currently have 55 vertical wells and 47 horizontal wells in the area.

Horizontal well fracs substantially reduce the number of drilling locations and the area of surface impact.

While much of the knowledge and skill required to make the change to horizontal wells were already inherent on the team, they employed advanced techniques imported from colleagues in the Barnett Shale in Texas that significantly lowered well completion costs and time. In a second step change adopted from offshore applications, that same Montney team in British Columbia was again

able to reduce well completion times, this time by half – a significant achievement that they, in turn, transferred to those same EnCana colleagues operating in Texas.

The asset team's resourcefulness has propelled the progress that has been made in the Montney, first with the horizontal well testing phase in early 2006, to full implementation in 2007. Costs are down by more than 33 percent per completed interval and we are drilling longer wells faster. In addition, the team has significantly reduced the environmental impacts of our operations in combination with company-leading safety performance.

Wood River Refinery

Did you know?

EnCana and our partner, ConocoPhillips, each own a 50 percent interest in the Wood River and Borger refineries. In addition to enabling the Borger Refinery to upgrade heavy oil blends, particularly Canadian bitumen, the 25,000 barrel-per-day coker project completed in 2007 also allows Borger to reduce SO_2 emissions and meet clean fuel regulations for producing ultra-low sulphur diesel and low sulphur gasoline.

Integrated oil

Our business venture with ConocoPhillips, established in January 2007, linked our upstream in-situ* bitumen developments with downstream refining, allowing us to capture the full value chain from our developing bitumen resources. Through this venture, we acquired a 50 percent interest in ConocoPhillips' Wood River and Borger refineries in Illinois and Texas respectively, and ConocoPhillips acquired a 50 percent interest in our Foster Creek and Christina Lake steam-assisted gravity drainage (SAGD) projects in northeast Alberta. EnCana operates the upstream business and ConocoPhillips operates the downstream business.

Our successful first year as an integrated oil business generated operating cash flow** of about $1.3 billion in 2007.

This integration builds a clear, sustainable, profitable path for the growth of our large bitumen resource. In 2007, we increased production about 25 percent on a pro forma basis to approximately 26,800 barrels per day. By 2015, we expect to increase bitumen production to 200,000 barrels per day net to EnCana.

Coker installation successfully completed at Borger

The installation of a coker was completed at Borger in June 2007, providing the refinery with the ability to upgrade approximately 20,000 barrels of bitumen per day. The Wood River Refinery is planning to add coking capacity to increase its ability to upgrade and refine bitumen.

A coker uses a thermal process for upgrading heavy hydrocarbon residue from crude oil into high-value products, such as gasoline, diesel and jet fuel.

Adding coking capacity to a refinery is beneficial because it allows refineries to process the growing volumes of North American heavy oil, including bitumen. Additionally, by increasing the coking capacity at our refineries we reduce the development and marketing risk of our vast bitumen resources at Foster Creek and Christina Lake.

306 Mbbls/d

Wood River Refinery in Roxanna, Illinois is ConocoPhillips' largest refinery, with 306,000 barrels per day crude oil throughput capacity.

- 50 Mbbls/d bitumen upgrading capacity
- Clean product yield: 80%
- Well-connected to key crude oil pipelines and able to source Canadian crude
- Excellent access to product markets in St. Louis and Chicago

146 Mbbls/d

Borger Refinery, located in the Texas panhandle, has 146,000 barrels per day crude oil throughput capacity.

- 20 Mbbls/d bitumen upgrading capacity
- 45 Mbbls/d NGL processing capacity
- Clean product yield: 90%
- Key product markets located in Texas, New Mexico and Colorado

***In-situ:** the process of separating bitumen from sand while the bitumen is still in the ground.

****Operating cash flow:** revenues, net of royalties less production and mineral taxes, transportation and selling, operating and purchased product expenses.

A proven in-situ oil development leader using SAGD technology

Not all bitumen resources are the same. At EnCana, we believe we have some of the best properties in northeast Alberta, with mineral rights to more than 1.4 million net acres. Whereas bitumen in oilsands deposits close to the surface is developed using mining techniques, our bitumen resources are all contained in deeper reservoirs. This allows us to use SAGD, an in-situ (in place) technology which is more capital and energy efficient, and has a smaller environmental footprint.

With more than 10 years experience operating SAGD projects, we have established a distinct presence as a technology leader.

Our deep bitumen reservoirs allow us to use technologies that have a smaller environmental footprint than bitumen in oilsands deposits that are surface mined.

In general, in-situ bitumen is a thick crude that cannot be economically produced by conventional methods. We currently use SAGD technology, a thermal process using paired horizontal wells that inject steam into the reservoir through one well to melt the bitumen so it can be pumped to the surface through the other well. Our highly experienced technical teams have developed sophisticated methods that place our projects among the most economic and efficient in-situ developments in the industry.

As part of our plan to increase our share of the bitumen production to 200,000 barrels per day by 2015, we are expanding our operations at Foster Creek and Christina Lake. In both our existing operations and expansions, safety, responsible water use, emissions and the size of our surface land footprint are top of mind for everyone working on our projects. While our teams are proud of the success they've achieved in these areas, they continue to pursue new, better and more efficient ways to extract the resources.

Foster Creek and Christina Lake expansion highlights*

- In 2007, we completed an expansion phase at Foster Creek, taking production capacity to 60,000 barrels per day.
- The next two phases at Foster Creek, each 30,000 barrel-per-day expansions, are expected to come on stream by the end of 2008 and mid-2009 respectively.
- Christina Lake is expected to grow productive capacity to 18,000 barrels per day by mid-2008 and development is underway for an additional 40,000 barrel-per-day expansion with initial production expected in 2011.

*Capacity is noted on a 100% basis.

Foster Creek: approximately 150 acres

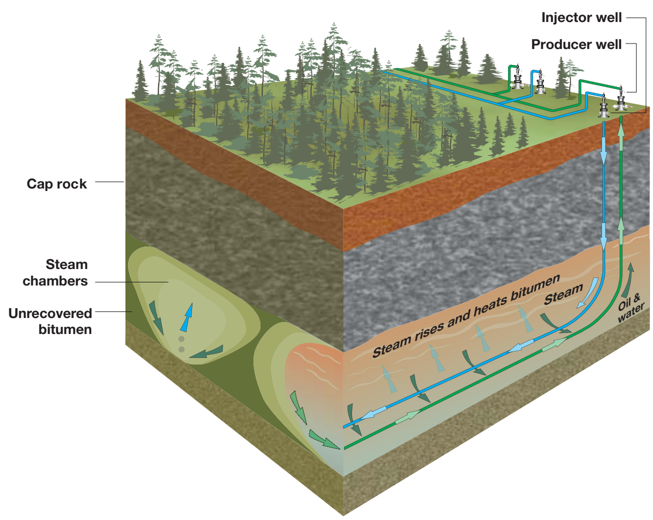
Christina Lake: approximately 200 acres

Foster Creek and Christina Lake processing plants occupy surface space about the size of small Alberta farms.

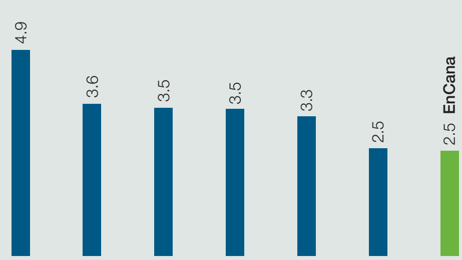
Our bitumen resources are distinctly different from oilsands deposits near the surface. Our resources allow us to take advantage of in-situ SAGD to recover the bitumen rather than recovering it by surface mining.

Steam-assisted gravity drainage: a thermal recovery process using paired horizontal wells

The first of the two horizontal wells – the bitumen producer well – is placed near the bottom of the reservoir. Steam is injected into the second well, which is placed approximately five metres above and parallel to the producer well. The steam heats and melts the bitumen, which enables gravity to assist it to drain into the producer well below, which then (combined with condensed water from the steam) comes through the wellbore to the surface.



EnCana is an industry leader with a steam-oil-ratio of 2.5 barrels of steam for every barrel of oil recovered



Peer companies include CNRL Primrose, IMO, JACOS, Petro-Canada, Shell, and Suncor

Source: Based on Energy Resources Conservation Board data

Innovation at work

An ongoing goal of our oil teams is to find ways to reduce every input into our operations, such as water, steam, steel, natural gas and electricity, and our surface land disturbance, in order to increase the output of oil.

Below are two examples of their ingenuity to increase overall recovery of each well.

Electric submersible pumps (ESPs)

Specifically designed for use in SAGD operations, ESPs work at higher temperature and allow lower pressure operations. With lower pressure SAGD, steam requirements are reduced, thereby minimizing our water and energy use. This gives us a steam-oil-ratio (SOR) of about 2.5 barrels of steam for every barrel of oil recovered, making us a leader in this fundamental measure of SAGD efficiency and performance. These efficiency gains also result in lower operating costs and reduced greenhouse gas emissions.

Solvent-aided process (SAP)

Piloted at our Christina Lake project, SAP is an advanced SAGD technique that combines a solvent, such as butane, with the steam to help dissolve the bitumen and improve recovery from the reservoir. By implementing this process, we expect to use 30 percent less steam per barrel of oil produced, resulting in reduced natural gas and water consumption, and greenhouse gas emissions. Piloting SAP in our in-situ oil operations has demonstrated an enhanced oil production rate up to 30 percent higher than steam-only SAGD.

Did you know?

In addition to investing more than C$23 million towards projects in the areas of air emissions, renewable energy, energy efficiency and water conservation through our Environmental Innovation Fund, EnCana has committed C$50 million towards energy efficiency initiatives across our operations in 2008.

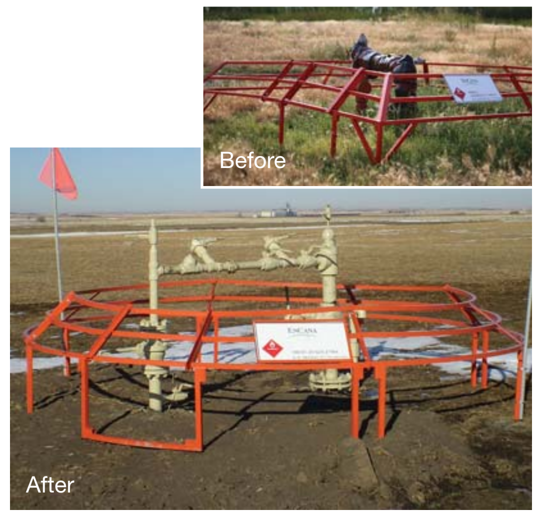
Community

At EnCana, we strive to conduct ourselves and our development activities in a manner intended to earn the confidence of our many stakeholders. It is important to us that we are an integral part of the communities where we work and live. Whether we have been in an area for many years or are new to a community, we take that responsibility seriously. We entrust our staff to apply continuous improvements – big and small – to all areas of our business by:

- regularly reviewing our activities in the communities in which we operate
- seeking feedback on our role as a neighbour from landowners, residents, communities and other stakeholders

New Tex fence design an example of our commitment to continuously improve

A discussion with a farmer on the concerns he had with the square Tex fences – the metal fence constructed around a gas wellhead (often the main above-ground indication of gas production after a shallow gas well has been drilled and brought into production) – led to a complete re-examination of the fence design. An EnCana team came up with the solution to make the fence round – addressing the lower crop yield and additional time it was taking to farm around the fence. We began replacing fences in 2007, and plan to expand the program in 2008.



Courtesy – an important value at EnCana

Our award-winning Courtesy Matters™ program emphasizes the shared responsibility contractors and employees have in demonstrating respect and courtesy to the communities in which we operate.

Investing in our communities

From monetary investments, to the provision of goods and services, we look for opportunities that will make a positive, long-lasting difference to a community. EnCana's support totalled more than C$30 million in 2007. And through our employee charitable giving program, EnCana Cares, EnCana matches the donations employees make. Together, employees and EnCana raised more than C$3.5 million in 2007, benefiting more than 1,000 not-for-profit organizations. We also encourage our employees to become involved in their communities. Our Employee Volunteer Program promotes and supports volunteerism by providing monetary donations to those organizations to which employees have volunteered time, either individually or as a family.

Did you know?

EnCana's enhanced oil recovery facility in Weyburn, Saskatchewan is the world's largest carbon dioxide (CO_2) sequestration project. So far, more than 10 million tonnes of CO_2 have been injected deep underground. About 30 million tonnes of CO_2 will be stored over the life of the project – the equivalent of taking 6.7 million cars off the road for a year.

Environment

As a significant producer of two vital energy sources, EnCana is committed to ensuring that all our operations are undertaken with the highest standards of environmental responsibility. More than 80 percent of our production is natural gas – the cleanest burning of all hydrocarbon-based fuels. And our bitumen production from northeast Alberta is in-situ.* By their nature, in-situ operations require a much smaller physical footprint than open pit oilsands mining. As well, we use less water for every barrel of oil produced when compared to our competitors with similar facilities. Across our oil and gas operations, we continuously look for ways to evolve both our processes and the technology we use to reduce our overall environmental footprint and increase efficiencies. More information about our corporate responsibility practices appears in our Corporate Responsibility Report, which will be published in June.

Striving to minimize our water use

As an industry leader, EnCana strives for more efficient water use in all our operations through sound and innovative water management practices. For example, our in-situ oil teams have been successful in reducing the amount of water used in our SAGD projects, which require steam to heat the bitumen in order to get it out of the ground. In addition to innovative technologies such as electric submersible pumps and our newly piloted solvent-aided process to reduce our water use, our in-situ oil teams use saline water – which is unfit for human, livestock or wildlife consumption – recycled produced water, and a small amount of new fresh water. In fact, we are currently recycling more than 90 percent of the water used at Foster Creek and approximately 75 percent at Christina Lake.

Clean energy solutions

We're also committed to investing in clean energy technology solutions. Through our Environmental Innovation Fund, we invest in people and ideas that are addressing future solutions. Since its inception, the fund has invested more than C$23 million in the areas of air emissions, renewable energy, energy efficiency and water conservation. Two examples of the types of projects we invested in during 2007 are:

- Nova Scotia's first in-stream tidal technology centre with a C$3 million commitment to support the advancement of technologies that have the potential to provide new sources of clean renewable ocean energy.
- A C$3 million commitment to support NxtGen Emission Controls in field trials of its emission reduction technology. NxtGen Emission Controls is an emerging supplier of diesel emission reduction systems. NxtGen's innovative syngas technology provides a platform to reduce particulate matter, NO_x and greenhouse gas emissions for diesel engines, as well as increase fuel economy.

Recognition for our efforts

EnCana has received numerous awards and recognition for our operations. We are listed on the Dow Jones Sustainability World Index and were recently awarded a Silver Class distinction award in the 'Oil & Gas Producers' category in the Sustainability Yearbook 2008. Produced by Sustainable Asset Management (SAM) Group, the yearbook is considered the world's most comprehensive publication for sustainability trends such as climate change, new energy technologies and the global shortage of natural resources.

Dow Jones Sustainability Indexes
Member 2007/08

sam
creating sustainable value

*In-situ: the process of separating bitumen from sand while the bitumen is still in the ground.

EnCana recognized for wildlife research support

Determining how to extract energy reserves and minimize the impact on wildlife has proven to be a significant challenge for many years. That's why we have environmental scientists and biologists on our teams, and draw on outside experts when necessary. But we don't just leave it to the experts. As people who live in the communities where we operate, we all have a vested interest in the land, and take our responsibility as stewards of the land seriously. In Colorado, for example, the central Piceance Basin holds huge amounts of energy reserves valuable to North America. It also supports habitat for greater sage grouse, the state's largest migratory mule deer population, and winter range for elk and a diverse variety of other wildlife. We were recently recognized by the Colorado Wildlife Commission and Colorado Division of Wildlife for our support of wildlife conservation efforts to monitor and protect wildlife in that area. These efforts include:

- conducting annual fly overs to collect animal counts for the Colorado Division of Wildlife
- instituting organized efforts to improve the existing wildlife habitat
- developing long-term noxious weed control
- developing a poacher-detecting program with the Colorado Division of Wildlife

And we are currently working with the Colorado Division of Wildlife on three research projects to diminish the impact of natural gas and shale oil development on wildlife in the central Piceance Basin.

Energy efficiency – our everyday business

We are focused on finding and applying tangible and measurable reductions in energy use and emissions across our company. At the beginning of 2007, we launched an energy efficiency initiative that encourages employees to explore energy-efficient improvements within the company. Of the many ideas submitted by employees, more than 40 are currently in various stages of assessment to determine their viability. More than C$8 million of energy efficiency projects have been identified and financed, which have the potential to reduce CO_2 emissions by about 500,000 tonnes per year. Based on the success of these efforts in 2007, we have committed C$50 million towards energy efficiency initiatives in 2008.

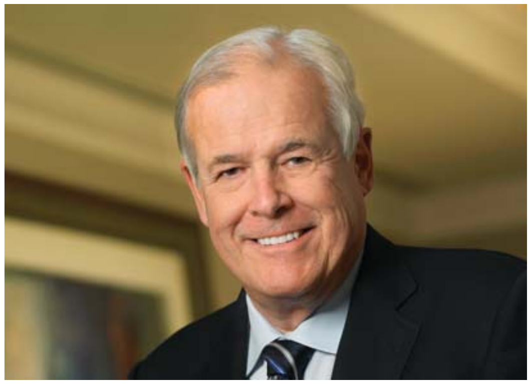
Another part of the initiative was the launch of an employee rebate program to encourage employees to incorporate energy efficiency into all aspects of their lives. And we have partnered with One Change, a not-for-profit Canadian organization on its Project Porchlight initiative, whereby EnCana is providing C$1 million to support compact fluorescent light (CFL) bulb delivery to interested communities where EnCana works and lives, beginning in Alberta. By January 2008, approximately 75,000 CFL bulbs had been delivered to households in more than 20 communities.

Energy efficiency in action

When information about a new infrared camera that detects volatile organic compounds came to our attention this past year, EnCana put it to the test. The camera provides real-time infrared detection of gas leaks that are too small to be seen by the human eye or sensed by gas detection instrumentation. In testing the camera, we found and repaired a number of leaks that would have normally gone undetected. While too small to pose a safety risk to the operators or the public, the leaks still represented waste and inefficiency that can be improved upon by the new technology. We are now using this technology across our operations.

In 2008 we have committed $50 million toward energy efficiency. Every day we strive to employ capital- and energy-efficient methods to minimize our environmental footprint and maximize the recovery of the resources we extract.

Chairman's letter



Integrity, trust and good governance are the pillars upon which the Board has and will continue to direct EnCana.

David P. O'Brien
Chairman of the Board

EnCana achieved considerable financial and operating success in 2007 as it increased shareholder value while acting in accordance with the well-established corporate governance practices mandated and overseen by the Board of Directors.

EnCana fully complies with the applicable corporate governance requirements, including best practices guidelines published by the Canadian securities regulatory authorities, the provisions of the Sarbanes-Oxley Act of 2002 (SOX) and the rules adopted by the U.S. Securities and Exchange Commission pursuant to that Act. We are also in compliance with all applicable New York Stock Exchange requirements. We are committed to the high standards of transparent reporting and accountability.

To help enhance the company's capacity for sustainable growth, EnCana decided in 2007 to establish the position of Chief Risk Officer. The purpose of this new position is to identify, analyze and recommend ways to mitigate all significant risks, including risks that have the potential to impact the sustainability of our resource play strategy.

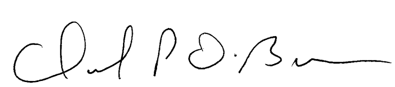
In 2007, EnCana also developed a new Competition and Antitrust Law Compliance Practice which provides clear direction for addressing competition-related matters in our business. An extensive training program has been developed as part of the new practice.

The Board continues to evaluate EnCana's environmental performance and environmental regulatory developments, in particular the emerging framework on greenhouse gases. As regulations develop, EnCana is analyzing the potential cost of compliance under a variety of scenarios and is participating with governments and industry in providing input into regulatory development. The company continues to advance opportunities and practices aimed at increasing the energy efficiency of operations and furthering carbon sequestration.

The Board had the pleasure of welcoming three new members. Allan Sawin is a Chartered Accountant who brings a wealth of experience in the oilfield services sector. Wayne Thomson adds expertise in North American and international oil and gas development. Clayton Woitas joined the Board in January 2008 and brings a broad range of experience in the Western Canadian oil and gas sector. Two long-serving Directors, Dennis Sharp and Ken McCready, are retiring from the Board in April. I thank them for their great contributions to EnCana and wish them well in their future endeavours.

I want to express my appreciation to EnCana shareholders for the confidence they continue to demonstrate in the company. My thanks are also extended to the Directors, EnCana's executive team and all employees and contractors. It's a pleasure to work with a group of people so dedicated to the common goal of ensuring EnCana's success.

On behalf of the Board of Directors,



David P. O'Brien
Chairman of the Board

Did you know?

Our newest rigs – known as fit-for-purpose rigs – are automated, allowing us to drill faster and more economically. Most importantly because they are automated, they create a safer work environment for our operators.

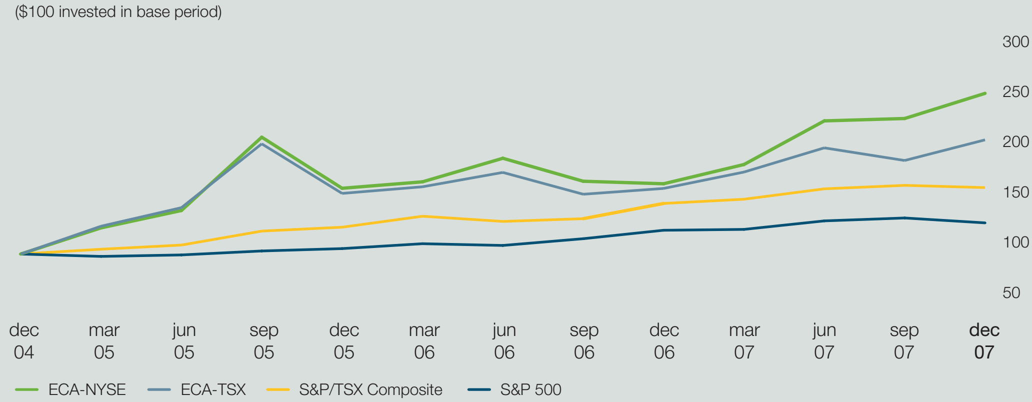
Select financial summary

US$ millions, except as noted	2007	2006	2005 (1)
Revenues, Net of Royalties	21,446	16,399	14,573
Operating Expense	2,278	1,655	1,438
Depreciation, Depletion & Amortization	3,816	3,112	2,769
Net Earnings	3,959	5,652	3,426
Per Share – Diluted	5.18	6.76	3.85
Operating Earnings (2)	4,100	3,271	3,241
Per Share – Diluted	5.36	3.91	3.64
Working Capital	(1,886)	11	(1,267)
Property, Plant & Equipment, Net	35,865	28,213	24,881
Total Assets	46,974	35,106	34,148
Long-Term Debt	8,840	6,577	6,703
Shareholders' Equity	20,704	17,466	16,007
Cash Flow (2)	8,453	7,161	7,426
Per Share – Diluted	11.06	8.56	8.35
Free Cash Flow	2,418	892	949
Common Shares Outstanding (millions)	750.2	777.9	854.9
Shares Purchased (millions of shares) (3)	38.9	85.6	55.2
Average Price	52.05	49.26	34.85
Dividends Per Common Share ($/share)	0.800	0.375	0.275
Dividend Yield (%) (4)	1.2	0.8	0.6
Total Capital from Continuing Operations	6,035	6,269	6,477
Net Acquisition & Divestiture Activity from Continuing Operations	2,221	(358)	(2,075)
Net Capital Investment	8,256	3,264	4,097
Net Debt to Capitalization (%)	34	27	33
Net Debt to Adjusted EBITDA (times) (2)	1.2	0.6	1.1

(1) Share data restated for the effects of the share splits approved.
(2) Non-GAAP measures are referenced in the Advisory on page 63.
(3) Shares purchased under Normal Course Issuer Bid.
(4) NYSE closing share price at year end.

Total return versus major indices

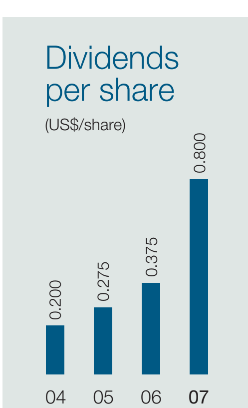
($100 invested in base period)



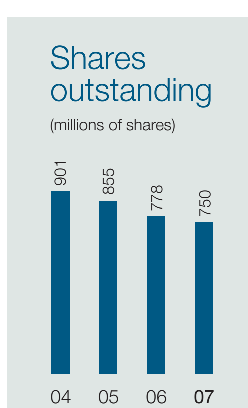
Operating summary

After royalties	2007 (1)	2006 (2)	2005 (2)
Production			
Continuing Operations – North America			
Natural Gas (MMcf/d)			
Canada	**2,221**	2,185	2,125
U.S.	**1,345**	1,182	1,095
Total Natural Gas (MMcf/d)	**3,566**	3,367	3,220
Oil & NGLs (bbls/d)			
Foster Creek & Christina Lake	**26,814**	42,768	34,379
North America, Other	**107,340**	114,505	122,428
Total Oil & NGLs (bbls/d)	**134,154**	157,273	156,807
Total Production from Continuing Operations (MMcfe/d)	**4,371**	4,311	4,161
Discontinued Operations			
Ecuador (bbls/d)	**–**	11,996	72,916
Total Production from Discontinued Operations (MMcfe/d)	**–**	72	437
Total Production (MMcfe/d)	**4,371**	4,383	4,598
Refinery Operations (3)			
Crude Oil Capacity (Mbbls/d)	**452**	–	–
Crude Oil Runs (Mbbls/d)	**432**	–	–
Proved Reserves			
Continuing Operations – North America			
Natural Gas (Bcf)			
Canada	**7,292**	7,028	6,517
U.S.	**6,008**	5,390	5,267
Total	**13,300**	12,418	11,784
Oil & NGLs (MMbbls)			
Foster Creek & Christina Lake	**595.5**	796.1	652.4
Canada, Other	**273.4**	283.3	280.1
U.S.	**58.3**	54.0	53.1
Total	**927.2**	1,133.4	985.6
Total Proved Reserves from Continuing Operations (Bcfe)	**18,863**	19,218	17,698
Discontinued Operations			
Ecuador (MMbbls)	**–**	–	135.0
Total Reserves (Bcfe)	**18,863**	19,218	18,507

(1) 2007 represents 50% of Foster Creek and Christina Lake production.
(2) 2006 and 2005 represent 100% of Foster Creek and Christina Lake production.
(3) Represents 100% of the Wood River and Borger refinery operations.



In 2007, EnCana doubled its annual dividend to 80 cents per share.



Over the period shown, EnCana purchased more than 219 million shares.

Management's Discussion and Analysis

Financial Statements

Did you know?

Overall, 91 percent of employees who participated in our annual Pulse Check survey in 2007 ranked EnCana as one of the best companies to work for. On almost all the factors, EnCana continues to rank in the upper 90th percentile, considerably higher than the norm for 500 other high-performing companies in North America.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the audited Consolidated Financial Statements for the year ended December 31, 2007, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2006. Readers should also read the "Forward-Looking Statements" legal advisory at the end of this MD&A and on page 61.

The Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 21, 2008.

Readers can find the definition of certain terms used in this MD&A in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisory section located on page 62 of this document.

EnCana's Business

EnCana is a leading North American unconventional natural gas and integrated oil company.

EnCana operates three business segments:

- Canada, United States and Other includes the Company's upstream exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities. The majority of the Company's upstream operations are located in Canada and the U.S. Offshore and international exploration is mainly focused on opportunities in Atlantic Canada, the Middle East and Europe.
- Integrated Oil is focused on two lines of business: the exploration for, and development and production of bitumen in Canada using in-situ recovery methods; and the refining of crude oil into petroleum and chemical products in the U.S. This segment represents EnCana's 50 percent interest in a joint venture with ConocoPhillips.
- Market Optimization is focused on enhancing the sale of EnCana's upstream production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operational flexibility for transportation commitments, product type, delivery points and customer diversification.

2007 Overview

In 2007 compared to 2006, EnCana:

- Formed a North American integrated oil business with ConocoPhillips;
- Reported a 20 percent increase in Cash Flow from Continuing Operations to $8,453 million primarily due to an increase of $1,018 million before-tax in Operating Cash Flow from the integrated oil business with ConocoPhillips and an increase of $760 million after-tax in realized financial hedging gains;
- Reported a 27 percent increase in Operating Earnings from Continuing Operations to $4,100 million;
- Reported a 23 percent decrease in Net Earnings from Continuing Operations to $3,884 million primarily due to after-tax unrealized mark-to-market losses of $811 million in 2007 compared with gains of $1,357 million in 2006 and a $255 million after-tax gain on divestiture of assets in Brazil in 2006;
- Reported a $1,526 million increase in Free Cash Flow to $2,418 million;
- Grew natural gas production 6 percent to 3,566 million cubic feet ("MMcf") of gas per day ("MMcf/d");
- Increased production from natural gas key resource plays 14 percent;
- Grew crude oil production 25 percent at Foster Creek and Christina Lake to 53,628 barrels per day ("bbls/d"). After reflecting the 50 percent contribution to the joint venture with ConocoPhillips, EnCana's reported production from these two properties decreased 37 percent to 26,814 bbls/d;
- Reported a 6 percent decrease in natural gas prices to $5.89 per thousand cubic feet ("Mcf"). Realized natural gas prices, including the impact of financial hedging, averaged $7.22 per Mcf, an increase of 7 percent;
- Acquired additional Deep Bossier natural gas and land interests in East Texas for approximately $2.55 billion before closing adjustments;
- Completed the sale of assets in Australia for $31 million, assets in the Mackenzie Delta and Beaufort Sea for $159 million and interests in Chad for $208 million;
- Entered into an agreement to sell its remaining interests in Brazil for approximately $165 million before closing adjustments;
- Purchased 38.9 million of its Common Shares, representing approximately 5 percent of the shares outstanding at the beginning of the year, at an average price of $52.05 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $2,025 million in 2007;
- Added net proved natural gas reserves of 2,184 billion cubic feet ("Bcf") and crude oil and NGLs reserves of 241 million barrels ("MMbbls") excluding the 398 MMbbls contributed to the integrated oil business;
- Was impacted by a 5 percent increase in the U.S./Canadian dollar exchange rate that increased reported total capital investment by $199 million, operating expense by $0.04 per thousand cubic feet equivalent ("Mcfe"), administrative expense by $0.01 per Mcfe and depreciation, depletion and amortization ("DD&A") by $130 million;
- Increased its annual dividend by 113 percent to 80 cents per share in 2007 compared to 37.5 cents per share in 2006;
- Increased its quarterly dividend to 40 cents per share for the first quarter of 2008; and
- Approved the development of the Deep Panuke natural gas project offshore Nova Scotia.

On January 2, 2007, EnCana became a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials, crack spreads and the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding EnCana's financial results:

Year ended December 31 (Average for the period)	2007	2007 vs 2006	2006	2006 vs 2005	2005
Natural Gas Price Benchmarks					
AECO (C$/Mcf)	**$ 6.61**	**-5%**	$ 6.98	-18%	$ 8.48
NYMEX ($/MMBtu)	**6.86**	**-5%**	7.22	-16%	8.62
Rockies (Opal) ($/MMBtu)	**3.95**	**-30%**	5.65	-19%	6.96
Texas (HSC) ($/MMBtu)	**6.58**	**1%**	6.53	-13%	7.54
Basis Differential ($/MMBtu)					
AECO/NYMEX	**0.75**	**-29%**	1.06	-33%	1.59
Rockies/NYMEX	**2.91**	**85%**	1.57	-5%	1.66
Texas/NYMEX	**0.28**	**-60%**	0.70	-35%	1.08
Crude Oil Price Benchmarks					
West Texas Intermediate (WTI) ($/bbl)	**72.41**	**9%**	66.25	17%	56.70
Western Canadian Select (WCS) ($/bbl)	**49.50**	**11%**	44.69	23%	36.39
Differential – WTI/WCS ($/bbl)	**22.91**	**6%**	21.56	6%	20.31
Refining Margin Benchmark					
Chicago 3-2-1 Crack Spread ($/bbl) (1)	**17.67**	**32%**	13.38	11%	12.03
Foreign Exchange					
U.S./Canadian Dollar Exchange Rate	**0.930**	**5%**	0.882	7%	0.825

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2005 and 2006 are calculated using Low Sulphur Diesel; 2007 is calculated using Ultra Low Sulphur Diesel.

Acquisitions and Divestitures

On November 20, 2007, EnCana acquired all of the Deep Bossier natural gas and land interests of privately owned Leor Energy group in East Texas for approximately $2.55 billion before closing adjustments, increasing EnCana's interest to 100 percent in these lands.

In keeping with EnCana's North American resource play and refining operations strategy, the Company completed the following divestitures in 2007:

- The sale of assets in Australia on August 15 for $31 million resulting in a gain on sale of $30 million before-tax ($25 million after-tax);
- The sale of its assets in the Mackenzie Delta and Beaufort Sea on May 30 for $159 million;
- The sale of its interests in Chad on January 12 for $208 million resulting in a gain on sale of $59 million; and
- The sale of other minor properties.

In addition to these divestitures, EnCana completed the sale of The Bow office project assets on February 9, 2007 for approximately $57 million, largely representing its investment at the date of sale.

Proceeds from these divestitures were directed primarily to the purchase of shares under EnCana's NCIB.

On September 13, 2007, EnCana reached an agreement to sell its remaining interests in Brazil for approximately $165 million before closing adjustments. The sale is subject to closing conditions and regulatory approvals, which are expected to be completed in the first half of 2008.

Consolidated Financial Results

($ millions, except per share amounts)	2007	Q4	Q3	Q2	Q1	2006	Q4	Q3	Q2	Q1	2005
Total Consolidated											
Cash Flow (1)	**$ 8,453**	**$ 1,934**	**$ 2,218**	**$ 2,549**	**$ 1,752**	$ 7,161	$ 1,761	$ 1,894	$ 1,815	$ 1,691	$ 7,426
per share – diluted	**11.06**	**2.56**	**2.93**	**3.33**	**2.25**	8.56	2.18	2.30	2.15	1.96	8.35
Net Earnings	**3,959**	**1,082**	**934**	**1,446**	**497**	5,652	663	1,358	2,157	1,474	3,426
per share – basic	**5.23**	**1.44**	**1.24**	**1.91**	**0.65**	6.89	0.84	1.68	2.60	1.74	3.95
per share – diluted	**5.18**	**1.43**	**1.24**	**1.89**	**0.64**	6.76	0.82	1.65	2.55	1.70	3.85
Operating Earnings (2)	**4,100**	**849**	**1,032**	**1,369**	**850**	3,271	675	1,078	824	694	3,241
per share – diluted	**5.36**	**1.12**	**1.37**	**1.79**	**1.09**	3.91	0.84	1.31	0.98	0.80	3.64
Total Assets	**46,974**					35,106					34,148
Long-Term Debt	**8,840**					6,577					6,703
Cash Dividends – per share	**0.800**	**0.200**	**0.200**	**0.200**	**0.200**	0.375	0.100	0.100	0.100	0.075	0.275
Continuing Operations											
Cash Flow from Continuing Operations (1)	**8,453**	**1,934**	**2,218**	**2,549**	**1,752**	7,043	1,742	1,883	1,839	1,579	6,962
Net Earnings from Continuing Operations	**3,884**	**1,007**	**934**	**1,446**	**497**	5,051	643	1,343	1,593	1,472	2,829
per share – basic	**5.13**	**1.34**	**1.24**	**1.91**	**0.65**	6.16	0.81	1.66	1.92	1.74	3.26
per share – diluted	**5.08**	**1.33**	**1.24**	**1.89**	**0.64**	6.04	0.80	1.63	1.88	1.70	3.18
Operating Earnings from Continuing Operations (2)	**4,100**	**849**	**1,032**	**1,369**	**850**	3,237	672	1,064	841	660	3,048
Revenues, Net of Royalties	**21,446**	**5,801**	**5,596**	**5,613**	**4,436**	16,399	3,676	4,029	3,922	4,772	14,573

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are defined under the "Cash Flow" section of this MD&A.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are defined under the "Operating Earnings" section of this MD&A.

CASH FLOW

Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows. Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash Flow excluding Cash Flow from Discontinued Operations, which is defined on the Consolidated Statement of Cash Flows. While Cash Flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and are used by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Summary of Cash Flow from Continuing Operations

($ millions)	2007	2006	2005
Cash from Operating Activities	**$ 8,429**	$ 7,973	$ 7,430
(Add back) deduct:			
Cash Flow from Discontinued Operations	**–**	118	464
Net change in other assets and liabilities	**(16)**	138	(281)
Net change in non-cash working capital from Continuing Operations	**(8)**	3,343	497
Net change in non-cash working capital from Discontinued Operations	**–**	(2,669)	(212)
Cash Flow from Continuing Operations	**$ 8,453**	$ 7,043	$ 6,962

2007 versus 2006

EnCana's 2007 Cash Flow of $8,453 million increased $1,292 million or 18 percent compared to 2006 Cash Flow of $7,161 million.

Cash Flow from Continuing Operations in 2007 was $8,453 million (2006 – $7,043 million).

The increase in Cash Flow from Continuing Operations in 2007 compared with 2006 resulted from:

- Operating Cash Flow from the Integrated Oil business was $1,294 million in 2007 compared to $276 million in 2006;
- Realized financial natural gas, crude oil and other hedging gains were $1,023 million after-tax in 2007 compared with gains of $263 million after-tax in 2006;
- Natural gas production volumes in 2007 increased 6 percent to 3,566 MMcf/d from 3,367 MMcf/d in 2006; and
- Average North American liquids prices, excluding financial hedges, increased 15 percent to $50.05 per bbl in 2007 compared to $43.71 per bbl in 2006.

Cash Flow from Continuing Operations was reduced by:

- Cash taxes were $1,554 million in 2007 compared to $942 million in 2006 primarily as a result of increased operating cash flows in the U.S. and higher realized financial hedging gains offset partially by a $179 million recovery due to a Canadian federal corporate tax legislative change;
- Average North American natural gas prices, excluding financial hedges, decreased 6 percent to $5.89 per Mcf in 2007 compared to $6.25 per Mcf in 2006; and
- North American liquids production volumes decreased 15 percent to 134,154 bbls/d in 2007 from 157,273 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek offset by EnCana's 50 percent contribution of the Foster Creek and Christina Lake properties to the joint venture with ConocoPhillips and natural declines in conventional properties.

2006 versus 2005

EnCana's 2006 Cash Flow was $7,161 million, a decrease of $265 million or 4 percent from 2005 mainly due to the decline in Cash Flow from Discontinued Operations of $346 million year over year.

Cash Flow from Continuing Operations in 2006 was $7,043 million (2005 – $6,962 million).

The increase in Cash Flow from Continuing Operations resulted from:

- Average North American liquids prices, excluding financial hedges, increased 21 percent to $43.71 per bbl in 2006 compared to $36.17 per bbl in 2005;
- North American natural gas production volumes in 2006 increased 4 percent to 3,367 MMcf/d from 3,227 MMcf/d in 2005; and
- Realized financial natural gas and crude oil hedging gains were $263 million after-tax in 2006 compared with losses of $441 million after-tax in 2005.

Cash Flow from Continuing Operations was reduced by:

- Average North American natural gas prices, excluding financial hedges, decreased 16 percent to $6.25 per Mcf in 2006 compared to $7.46 per Mcf in 2005;
- Operating expenses, which increased 15 percent to $1,655 million in 2006 compared with $1,438 million in 2005; and
- The current tax provision, excluding income tax on the 2006 sale of assets in Brazil, increased $267 million to $893 million in 2006 compared to $626 million in 2005, excluding income tax on sale of the Gulf of Mexico assets.

Q4 2007 versus Q4 2006

Cash Flow from Continuing Operations in 2007 was $1,934 million, an increase of $192 million or 11 percent compared to 2006.

The increase in Cash Flow from Continuing Operations resulted from:

- Average North American liquids prices, excluding financial hedges, increased 54 percent to $59.60 per bbl in 2007 compared to $38.69 per bbl in 2006;
- Operating Cash Flow from the integrated oil business was $222 million in 2007 compared to $93 million in 2006;
- Realized financial natural gas, crude oil and other hedging gains were $246 million after-tax in 2007 compared with gains of $160 million after-tax in 2006; and
- Natural gas production volumes in 2007 increased 9 percent to 3,722 MMcf/d from 3,406 MMcf/d in 2006.

Cash Flow from Continuing Operations was reduced by:

- Cash taxes were $580 million in 2007 compared to $113 million in 2006 primarily as a result of adjustments made to full year estimates, U.S. operations and higher realized financial hedging gains; and
- North American liquids production volumes decreased 12 percent to 136,137 bbls/d in 2007 from 154,669 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek offset by EnCana's 50 percent contribution of the Foster Creek and Christina Lake properties to the joint venture with ConocoPhillips and natural declines in conventional properties.

NET EARNINGS

2007 versus 2006

EnCana's 2007 Net Earnings were $3,959 million, a decrease of $1,693 million compared to 2006. Net Earnings from Discontinued Operations of $75 million in 2007 decreased $526 million from 2006 primarily due to sales of the gas storage business and Ecuador assets in 2006 (discussed in the Discontinued Operations section of this MD&A).

EnCana's 2007 Net Earnings from Continuing Operations were $3,884 million or $1,167 million lower than 2006. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

- Unrealized mark-to-market losses of $811 million after-tax in 2007 compared with gains of $1,357 million after-tax in 2006;
- DD&A increased $704 million in 2007 compared to 2006 primarily due to higher future development costs, the higher U.S./Canadian dollar exchange rate and the increase in production volumes. In addition, downstream refinery DD&A was $159 million in 2007 with no comparative amount in 2006;
- A gain on sale of approximately $255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil in 2006;
- Reductions in future tax in addition to the impact detailed above related to the unrealized mark-to-market; and
- Non-operating foreign exchange gains of $217 million after-tax in 2007 with no comparative amount in 2006.

2006 versus 2005

EnCana's 2006 Net Earnings were $5,652 million, an increase of $2,226 million compared to 2005. Net Earnings for the year included unrealized after-tax mark-to-market gains of $1,370 million (2005 – after-tax losses of $277 million) and the effect of the tax rate reduction of $457 million (2005 – nil). Net Earnings from Discontinued Operations increased slightly to $601 million in 2006, mainly due to the gain on sale of gas storage assets offset partially by the loss on sale of Ecuador assets (discussed in the Discontinued Operations section of this MD&A).

EnCana's 2006 Net Earnings from Continuing Operations were $5,051 million, an increase of $2,222 million compared with 2005. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Unrealized mark-to-market gains of $1,357 million after-tax in 2006 compared with losses of $311 million after-tax in 2005;
- A gain on sale of approximately $255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil; and
- An increase in DD&A of $343 million as a result of the higher U.S./Canadian dollar exchange rate, higher DD&A rates and increased production volumes.

Q4 2007 versus Q4 2006

EnCana's 2007 Net Earnings were $1,082 million, an increase of $419 million compared to 2006. Net Earnings from Discontinued Operations of $75 million in 2007 relate to final adjustments on the December 2005 sale of the Company's Midstream NGLs processing operations.

EnCana's 2007 Net Earnings from Continuing Operations were $1,007 million or $364 million higher compared to 2006. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

- Non-operating foreign exchange gains of $267 million after-tax in 2007 compared with losses of $128 million after-tax in 2006;
- Unrealized mark-to-market losses of $366 million after-tax in 2007 compared with gains of $99 million after-tax in 2006;
- DD&A increased $320 million in 2007 compared to 2006 primarily due to higher future development costs, the higher U.S./Canadian dollar exchange rate and the increase in production volumes; and
- Reductions in future tax, which include the impact detailed above related to the unrealized mark-to-market and $264 million due to rate reductions.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust Net Earnings and Net Earnings from Continuing Operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings	**2007**		2006		2005	
($ millions, except per share amounts)		**Per share** (5)		Per share (5)		Per share (5)
Net Earnings, as reported	**$ 3,959**	**$ 5.18**	$ 5,652	$ 6.76	$ 3,426	$ 3.85
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax	**(811)**	**(1.06)**	1,370	1.64	(277)	(0.31)
Non-operating foreign exchange gain (loss), after-tax (1)	**217**	**0.28**	—	—	92	0.10
Gain (loss) on discontinuance, after-tax (2)	**152**	**0.20**	554	0.66	370	0.42
Future tax recovery due to tax rate reductions	**301**	**0.40**	457	0.55	—	—
Operating Earnings (3) (4)	**$ 4,100**	**$ 5.36**	$ 3,271	$ 3.91	$ 3,241	$ 3.64

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, the partnership contribution receivable and realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.

(2) For 2007, primarily the sale of interests in Chad, assets in Australia and final adjustments on the NGL processing business sold in 2005; sale of storage facilities and interests in Ecuador for 2006; sale of NGL processing business for 2005.

(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions and the effect of changes in statutory income tax rates. In 2007, EnCana changed its calculation of Operating Earnings to exclude the foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(4) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.

(5) Per Common Share – diluted.

Summary of Operating Earnings from Continuing Operations

($ millions)	2007	2006	2005
Net Earnings from Continuing Operations, as reported	**$ 3,884**	$ 5,051	$ 2,829
Add back (losses) and deduct gains:			
Unrealized mark-to-market accounting gain (loss), after-tax	**(811)**	1,357	(311)
Non-operating foreign exchange gain (loss), after-tax (1)	**217**	—	92
Gain (loss) on discontinuance, after-tax (2)	**77**	—	—
Future tax recovery due to tax rate reductions	**301**	457	—
Operating Earnings from Continuing Operations (3) (4)	**$ 4,100**	$ 3,237	$ 3,048

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, the partnership contribution receivable and realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.

(2) Primarily the sale of interests in Chad and assets in Australia for 2007.

(3) Operating Earnings from Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions and the effect of changes in statutory income tax rates. In 2007, EnCana changed its calculation of Operating Earnings to exclude the foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(4) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate increased 5 percent to $0.930 in 2007 compared to $0.882 in 2006. The table below summarizes the quarterly and total year impacts of this increase on EnCana's operations when compared to the same periods in 2006.

	2007	Q4	Q3	Q2	Q1
Average U.S./Canadian Dollar Exchange Rate	**$ 0.930**	$ 1.019	$ 0.957	$ 0.911	$ 0.854
Decrease (increase) in:					
Total Capital Investment ($ millions)	**(199)**	(136)	(63)	(20)	20
Operating Expense ($/Mcfe)	**(0.04)**	(0.12)	(0.05)	(0.01)	0.01
Administrative Expense ($/Mcfe)	**(0.01)**	(0.03)	(0.01)	—	—
DD&A ($ millions)	**(130)**	(86)	(40)	(12)	8

RESULTS OF OPERATIONS

Production Volumes	2007	Q4	Q3	Q2	Q1	2006	Q4	Q3	Q2	Q1	2005
Produced Gas (MMcf/d)	**3,566**	**3,722**	**3,630**	**3,506**	**3,400**	3,367	3,406	3,359	3,361	3,343	3,220
Crude Oil (bbls/d)	**108,976**	**109,273**	**109,967**	**108,916**	**107,715**	133,066	130,563	132,814	127,459	141,552	131,225
NGLs (bbls/d)	**25,178**	**26,864**	**26,416**	**24,500**	**22,875**	24,207	24,106	23,907	24,400	24,421	25,582
Continuing Operations (MMcfe/d) (1)	**4,371**	**4,539**	**4,448**	**4,306**	**4,184**	4,311	4,334	4,299	4,272	4,339	4,161
Discontinued Operations Ecuador (bbls/d) (2)	**–**	**–**	**–**	**–**	**–**	11,996	—	—	—	48,650	72,916
Discontinued Operations (MMcfe/d) (1)	**–**	**–**	**–**	**–**	**–**	72	—	—	—	292	437
Total (MMcfe/d) (1)	**4,371**	**4,539**	**4,448**	**4,306**	**4,184**	4,383	4,334	4,299	4,272	4,631	4,598

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

(2) Ecuador interests sold on February 28, 2006.

Production volumes from continuing operations increased 1 percent or 60 million cubic feet equivalent per day ("MMcfe/d") in 2007 compared to 2006 due to:

- Increased production from EnCana's natural gas key resource plays of 14 percent in 2007 compared to 2006; offset by
- Decreased production from EnCana's crude oil key resource plays of 25 percent in 2007 compared to 2006 after reflecting the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips and as a result of natural declines in conventional properties.

Production volumes on a pro forma basis, after reflecting 100 percent of Foster Creek and Christina Lake production, increased 5 percent or 221 MMcfe/d in 2007 compared to 2006.

Key Resource Plays	Daily Production					Drilling Activity (net wells drilled)		
	2007	**2007 vs 2006**	2006	2006 vs 2005	2005	**2007**	2006	2005
Natural Gas (MMcf/d)								
Jonah	**557**	**20%**	464	7%	435	**135**	163	104
Piceance	**348**	**7%**	326	6%	307	**286**	220	266
East Texas	**143**	**44%**	99	10%	90	**35**	59	84
Fort Worth	**124**	**23%**	101	44%	70	**75**	97	59
Greater Sierra	**211**	**-1%**	213	-3%	219	**109**	115	164
Cutbank Ridge	**234**	**38%**	170	85%	92	**81**	116	135
Bighorn	**119**	**31%**	91	65%	55	**58**	52	51
CBM	**259**	**34%**	194	73%	112	**1,079**	729	1,245
Shallow Gas (1)	**726**	**-2%**	739	-3%	765	**1,914**	1,310	1,389
	2,721	**14%**	2,397	12%	2,145	**3,772**	2,861	3,497
Oil (Mbbls/d)								
Foster Creek	**49**	**31%**	37	27%	29	**45**	6	39
Christina Lake	**5**	**-13%**	6	9%	5	**7**	2	—
Partner's 50% Interest	**(27)**	**—**	—	—	—	**(26)**	—	—
	27	**-37%**	43	24%	34	**26**	8	39
Pelican Lake	**23**	**-1%**	24	-9%	26	**—**	—	52
	50	**-25%**	66	10%	60	**26**	8	91
Total (MMcfe/d)	**3,021**	**8%**	2,795	12%	2,506	**3,798**	2,869	3,588

(1) Shallow Gas volumes and net wells drilled report commingled volumes from multiple zones within the same geographic area as a result of regulatory approval, which was received in late 2006. Figures for 2005 and 2006 have been restated accordingly.

CANADA, UNITED STATES AND OTHER

Produced gas

Financial Results from Continuing Operations

($ millions, except per unit amounts in $ per thousand cubic feet)	Canada	$/Mcf	United States	$/Mcf	Total	$/Mcf
2007						
Revenues, Net of Royalties/Price	**$ 5,058**	**$ 6.20**	**$ 2,641**	**$ 5.38**	**$ 7,699**	**$ 5.89**
Realized Financial Hedging Gain	**613**		**1,124**		**1,737**	
Expenses						
Production and mineral taxes	**70**	**0.09**	**167**	**0.34**	**237**	**0.18**
Transportation and selling	**285**	**0.35**	**307**	**0.62**	**592**	**0.45**
Operating	**744**	**0.92**	**323**	**0.65**	**1,067**	**0.82**
Operating Cash Flow/Netback (1)	**$ 4,572**	**$ 4.84**	**$ 2,968**	**$ 3.77**	**$ 7,540**	**$ 4.44**
Netback including Realized Financial Hedging						**$ 5.77**
Gas Production Volumes (MMcf/d)		**2,221**		**1,345**		**3,566**
2006						
Revenues, Net of Royalties/Price	$ 4,968	$ 6.20	$ 2,742	$ 6.35	$ 7,710	$ 6.25
Realized Financial Hedging Gain	472		112		584	
Expenses						
Production and mineral taxes	80	0.10	213	0.49	293	0.24
Transportation and selling	278	0.35	248	0.54	526	0.42
Operating	629	0.79	283	0.65	912	0.74
Operating Cash Flow/Netback (1)	$ 4,453	$ 4.96	$ 2,110	$ 4.67	$ 6,563	$ 4.85
Netback including Realized Financial Hedging						$ 5.32
Gas Production Volumes (MMcf/d)		2,185		1,182		3,367
2005						
Revenues, Net of Royalties/Price	$ 5,669	$ 7.27	$ 3,126	$ 7.82	$ 8,795	$ 7.46
Realized Financial Hedging Loss	(183)		(194)		(377)	
Expenses						
Production and mineral taxes	76	0.10	325	0.81	401	0.34
Transportation and selling	283	0.36	182	0.46	465	0.40
Operating	521	0.67	212	0.53	733	0.62
Operating Cash Flow/Netback (1)	$ 4,606	$ 6.14	$ 2,213	$ 6.02	$ 6,819	$ 6.10
Netback including Realized Financial Hedging						$ 5.78
Gas Production Volumes (MMcf/d)		2,125		1,095		3,220

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)	2006 Revenues Net of Royalties	Revenue Variances in: Price (1)	Revenue Variances in: Volume	Revenue Variances in: Other (2)	**2007 Revenues Net of Royalties**
Canada	$ 5,440	$ 132	$ 91	$ 8	**$ 5,671**
United States	2,854	455	456	—	**3,765**
Total Produced Gas	$ 8,294	$ 587	$ 547	$ 8	**$ 9,436**

(1) Includes the impact of realized financial hedging.

(2) Includes Gas-over-Bitumen revenues resulting from wells shut-in or denied production that are received from the Alberta Government.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared with 2006 due to:

- Realized financial hedging gains totaled $1,737 million or $1.33 per Mcf in 2007 compared to gains of $584 million or $0.47 per Mcf in 2006; and
- A 6 percent increase in natural gas production volumes offset by a 6 percent decrease in North American natural gas prices, excluding the impact of financial hedging.

Produced gas volumes in the U.S. increased 14 percent in 2007 as a result of drilling and operational success as well as new facilities at Jonah, East Texas, Fort Worth and Piceance. Fourth quarter 2007 produced gas volumes in the U.S. also benefited slightly from incremental volumes from the Deep Bossier acquisition (34 MMcf/d). Produced gas volumes in Canada increased 2 percent in 2007. Drilling success and new facilities in the key resource plays of CBM, Cutbank Ridge and Bighorn were offset by natural declines for conventional properties.

The decrease in EnCana's North American natural gas price in 2007, excluding the impact of financial hedges, reflects the decline in AECO and NYMEX benchmark prices and changes in the basis differentials. Variability in realized prices also reflects the weighting of EnCana's various gas stream volumes at their respective benchmark price, net of applicable basis differential.

Natural gas per unit production and mineral taxes in the U.S. decreased $0.15 per Mcf or 31 percent in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies and a reduction in the severance and ad valorem effective tax rate for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased 15 percent or $0.08 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance area.

Natural gas per unit operating expenses for Canada in 2007 were 16 percent or $0.13 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate discussed earlier, higher repairs and maintenance expenses and increased property taxes and lease rentals offset partially by decreased electricity costs. Operating costs in both Canada and the U.S. were also impacted by higher long-term compensation costs in 2007 compared to 2006 due to increases in the EnCana share price, which resulted in a $0.03 per Mcf increase in operating costs for North American natural gas.

2006 versus 2005

Revenues, net of royalties, decreased in 2006 compared with 2005 due to:

- A 16 percent decrease in North American natural gas prices, excluding the impact of financial hedging; offset by
- A 5 percent increase in natural gas production volumes; and
- Realized financial hedging gains totaled $584 million or $0.47 per Mcf in 2006 compared to losses of $377 million or $0.32 per Mcf in 2005.

Produced gas volumes in Canada increased 3 percent in 2006, mainly due to drilling success in the key resource plays of CBM, Cutbank Ridge and Bighorn and additional well tie-ins and recompletions in several areas. CBM is the commingled gas volumes from the coal and sand intervals based on regulatory approval. Offsetting the increase were unscheduled maintenance, natural declines, planned turnarounds and weather related delays for the Shallow Gas key resource play and conventional properties, which resulted in lower production volumes. Produced gas volumes in the U.S. increased 8 percent in 2006 as a result of drilling success at Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

EnCana's North American natural gas price for 2006, excluding the impact of financial hedges, was $6.25 per Mcf, a decrease of 16 percent from 2005, consistent with the decline in the AECO price of 18 percent and the NYMEX price of 16 percent. North American realized financial hedging gains on natural gas for 2006 were approximately $584 million or $0.47 per Mcf compared to losses of approximately $377 million or $0.32 per Mcf in 2005. The hedging gains in 2006 were a result of put hedging instruments transacted at higher price levels than in 2005, coupled with a decline in North American natural gas prices in 2006 compared to 2005.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, remained flat in Canada for 2006 mainly due to lower natural gas prices offset partially by the higher U.S./Canadian dollar exchange rate. Natural gas per unit production and mineral taxes in the U.S. decreased $0.32 per Mcf or 40 percent in 2006 mainly as a result of a reduction in the effective production and severance tax rates for Colorado properties and lower natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased $0.08 per Mcf or 17 percent for 2006 primarily as a result of higher transportation costs on operated wells from Piceance, East Texas and certain Colorado properties.

Natural gas per unit operating expenses in Canada for 2006 were 18 percent or $0.12 per Mcf higher as a result of the higher U.S./Canadian dollar exchange rate, increased industry activity, property taxes and lease rentals, electricity rates and salaries and benefits. Natural gas per unit operating expenses in the U.S. increased 23 percent or $0.12 per Mcf for 2006 mainly as a result of increased industry activity, chemicals, salaries, workovers and repairs and maintenance expenses. Increases in operating costs in both Canada and the U.S. were offset partially by lower long-term compensation costs in 2006 compared to 2005.

Crude oil and NGLs

Financial Results from Continuing Operations ($ millions)	Canada [1]	United States	Total
2007			
Revenues, Net of Royalties	**$ 1,645**	**$ 309**	**$ 1,954**
Expenses			
Production and mineral taxes	**32**	**22**	**54**
Transportation and selling	**42**	**—**	**42**
Operating	**266**	**—**	**266**
Operating Cash Flow	**$ 1,305**	**$ 287**	**$ 1,592**
2006			
Revenues, Net of Royalties	$ 1,530	$ 267	$ 1,797
Expenses			
Production and mineral taxes	36	20	56
Transportation and selling	52	—	52
Operating	237	—	237
Operating Cash Flow	$ 1,205	$ 247	$ 1,452
2005			
Revenues, Net of Royalties	$ 1,297	$ 245	$ 1,542
Expenses			
Production and mineral taxes	28	24	52
Transportation and selling	17	—	17
Operating	206	—	206
Operating Cash Flow	$ 1,046	$ 221	$ 1,267

(1) Excludes Foster Creek/Christina Lake, which are discussed under Integrated Oil.

Crude Oil and NGLs Revenue Variances for 2007 Compared to 2006 from Continuing Operations ($ millions)	2006 Revenues Net of Royalties	Revenue Variances in: Price [1]	Revenue Variances in: Volume	**2007 Revenues Net of Royalties**
Canada [2]	$ 1,530	$ 221	$ (106)	**$ 1,645**
United States	267	15	27	**309**
Total Crude Oil and NGLs	$ 1,797	$ 236	$ (79)	**$ 1,954**

(1) Includes the impact of realized financial hedging.

(2) Excludes Foster Creek/Christina Lake, which are discussed under Integrated Oil.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared with 2006 due to:

- A 13 percent increase in Canada crude oil and 11 percent increase in North American NGLs prices, excluding financial hedges partially offset by a 6 percent decrease in North American liquids production volumes; and
- Realized financial hedging losses on liquids totaled $110 million or $3.05 per bbl in 2007 compared to losses of $125 million or $3.32 per bbl in 2006.

Canada crude oil production decreased 9 percent primarily due to natural declines in conventional properties.

2006 versus 2005

Revenues, net of royalties, increased in 2006 compared with 2005 due to:

- A 16 percent increase in Canada crude oil and 16 percent increase in North American NGLs prices, excluding financial hedges; and
- Realized financial hedging losses on liquids totaled $125 million or $3.32 per bbl in 2006 compared to losses of $218 million or $5.18 per bbl in 2005.

North American crude oil and NGLs volumes decreased 6 percent due to the Pelican Lake royalty payout, unscheduled maintenance, delays in capital programs in southern Alberta and natural declines. EnCana's Pelican Lake property reached payout in April 2006 which increased the royalty payments to the Alberta Government and reduced EnCana's net revenue interest crude oil volumes by approximately 6,000 bbls/d from the point of payout.

Per Unit Results – Crude Oil		Canada (1)	
($ per barrel)	**2007**	2006	2005
Price (2)	**$ 50.76**	$ 44.83	$ 38.49
Expenses			
Production and mineral taxes	**1.09**	1.11	0.79
Transportation and selling	**1.32**	0.91	1.08
Operating	**9.03**	7.69	5.90
Netback	**$ 39.32**	$ 35.12	$ 30.72
Crude Oil Production Volumes (bbls/d)	**82,162**	90,298	96,846

(1) Excludes Foster Creek/Christina Lake, which are discussed under Integrated Oil.
(2) Excludes the impact of realized financial hedging.

2007 versus 2006

Canada crude oil prices in 2007 increased 13 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006. Total realized financial hedging losses on crude oil for Canada were approximately $96 million or $3.20 per bbl in 2007 compared to losses of approximately $110 million or $3.43 per bbl in 2006.

Canada crude oil per unit transportation and selling costs increased 45 percent or $0.41 per bbl in 2007 compared to 2006 due to increased clean oil trucking costs at Weyburn, the higher U.S./Canadian dollar exchange rate and additional marketing costs.

Canada crude oil per unit operating costs in 2007 increased 17 percent or $1.34 per bbl compared to 2006 mainly due to the higher U.S./Canadian dollar exchange rate, increased workovers, higher long-term compensation costs due to the increase in the EnCana share price and increased chemicals offset partially by decreased electricity costs.

2006 versus 2005

The increase in EnCana's Canada crude oil price for 2006, excluding the impact of financial hedges, reflects the 17 percent increase in the benchmark WTI crude oil price compared to 2005. Canada realized financial hedging losses on crude oil were approximately $110 million or $3.43 per bbl for 2006 compared to losses of approximately $218 million or $6.21 per bbl for 2005. The reduced hedging losses in 2006 were a result of fixed price and put hedging instruments transacted at higher price levels than in 2005, coupled with an increase in benchmark oil prices in 2006 compared to 2005.

Canada crude oil production in 2006 decreased 7 percent from 2005 as a result of the Pelican Lake royalty payout in April 2006, property dispositions and declining production on conventional properties.

Canada crude oil per unit production and mineral taxes increased 41 percent or $0.32 per bbl in 2006 primarily due to increased production from the Weyburn and Senlac properties in Saskatchewan, which are subject to freehold production tax and Saskatchewan resource tax, the higher U.S./Canadian dollar exchange rate and the impact of higher overall prices.

Canada crude oil per unit transportation and selling costs decreased 16 percent or $0.17 per bbl in 2006 primarily due to lower transportation costs resulting from the disposition of properties with higher rates and costs in 2005.

Canada crude oil per unit operating costs for 2006 increased 30 percent or $1.79 per bbl mainly due to the higher U.S./Canadian dollar exchange rate, increased electricity rates, a prior period adjustment for a non-operated property, increased industry activity and lower production from Pelican Lake as a result of the royalty payout in the second quarter of 2006.

Per unit results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas. Costs directly associated with NGLs production such as production and mineral taxes and transportation and selling costs totaled $26 million in 2007 compared to $22 million in 2006.

Upstream depreciation, depletion and amortization

EnCana uses full cost accounting and calculates DD&A on a country-by-country cost centre basis. Accordingly, the DD&A rate for Canada and Foster Creek/Christina Lake are the same.

2007 versus 2006

Upstream DD&A expenses of $3,423 million in 2007 increased $555 million or 19 percent compared to 2006 due to:

- North American production volumes excluding Foster Creek/Christina Lake increased 4 percent;
- DD&A rates in 2007 were higher than 2006 primarily as a result of increased future development costs and the higher U.S./Canadian dollar exchange rate; and
- DD&A in 2007 included impairments of $44 million and $24 million related to exploration prospects in France and Oman, respectively compared to $6 million in 2006.

2006 versus 2005

Upstream DD&A expenses of $2,868 million in 2006 increased $296 million or 12 percent compared to 2005 due to:

- North American production volumes excluding Foster Creek/Christina Lake increased 2 percent;
- DD&A rates in 2006 were higher than 2005 as a result of the higher U.S./Canadian dollar exchange rate and an increase in future development costs partially reduced by the effect of the Gulf of Mexico sale in May 2005; and
- DD&A in 2006 included impairments of $6 million related to exploration prospects in the Middle East compared to $7 million in 2005.

INTEGRATED OIL

Foster Creek/Christina Lake operations

Financial Results from Continuing Operations

	Foster Creek/Christina Lake		
($ millions)	**2007**	2006	2005
Revenues, Net of Royalties	**$ 738**	$ 941	$ 529
Expenses			
Transportation and selling	**366**	476	350
Operating	**159**	194	137
Operating Cash Flow	**$ 213**	$ 271	$ 42

Crude Oil Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)	2006 Revenues Net of Royalties	Revenue Variances in: Price (1)	Volume	Other (2)	**2007 Revenues Net of Royalties**
Foster Creek/Christina Lake	$ 941	66	(168)	(101)	**738**

(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation expense.

2007 versus 2006

Revenues, net of royalties, decreased in 2007 compared with 2006 due to:

- A 37 percent decrease in Foster Creek/Christina Lake crude oil production volumes as a result of the joint venture with ConocoPhillips partially offset by a 10 percent increase in crude oil prices, excluding financial hedges. Production volumes on a pro forma basis, after reflecting 100 percent of Foster Creek and Christina Lake production, grew 25 percent to 53,628 bbls/d in 2007 compared to 2006;
- Realized financial hedging losses totaled $43 million or $3.88 per bbl in 2007 compared to losses of $62 million or $3.98 per bbl in 2006; and
- Lower condensate purchased for bitumen blending at Foster Creek/Christina Lake as a result of the joint venture with ConocoPhillips.

2006 versus 2005

Revenues, net of royalties, increased in 2006 compared with 2005 due to:

- A 66 percent increase in Foster Creek/Christina Lake crude oil prices, excluding financial hedges combined with a 24 percent increase in crude oil production volumes primarily as a result of continued development at Foster Creek; and
- Realized financial hedging losses totaled $62 million or $3.98 per bbl in 2006 compared to losses of $77 million or $6.16 per bbl in 2005.

Per Unit Results – Crude Oil

($ per barrel)	Foster Creek/Christina Lake 2007	2006	2005
Price (1)	**$ 40.14**	36.49	22.02
Expenses			
Transportation and selling	**2.88**	2.64	1.54
Operating	**14.46**	12.38	10.94
Netback	**$ 22.80**	$ 21.47	$ 9.54
Crude Oil Production Volumes (bbls/d)	**26,814**	42,768	34,379
Pro forma Production Volumes (bbls/d) (2)	**26,814**	21,384	17,190

(1) Excludes the impact of realized financial hedging.

(2) 2005 and 2006 production volumes adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the business venture with ConocoPhillips in 2007.

2007 versus 2006

Foster Creek/Christina Lake crude oil prices in 2007 increased 10 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 9 percent or $0.24 per bbl compared to 2006 due to a higher percentage of volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006 and the higher U.S./Canadian dollar exchange rate.

Foster Creek/Christina Lake crude oil per unit operating costs increased 17 percent or $2.08 per bbl in 2007 compared to 2006. This reflected increased purchased fuel costs at Foster Creek to steam new well pairs prior to commencing production, increased repairs and maintenance, salaries and benefits and chemicals. In addition, operating costs for 2007 compared to 2006 were impacted by the higher U.S./Canadian dollar exchange rate and higher long-term compensation costs due to the increase in the EnCana share price.

2006 versus 2005

The increase in Foster Creek/Christina Lake crude oil price for 2006, excluding the impact of financial hedges, reflects the 17 percent increase in the benchmark WTI crude oil price compared to 2005 and greater access to markets in the U.S. Gulf Coast. Foster Creek/Christina Lake realized financial hedging losses on crude oil were approximately $62 million or $3.98 per bbl for 2006 compared to losses of approximately $77 million or $6.16 per bbl for 2005. The reduced hedging losses in 2006 were a result of fixed price and put hedging instruments transacted at higher price levels than in 2005, coupled with an increase in benchmark oil prices in 2006 compared to 2005.

Per unit transportation and selling costs increased 71 percent or $1.10 per bbl in 2006 primarily due to a higher proportion of oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher U.S./Canadian dollar exchange rate. Crude oil transportation and selling costs also include costs of condensate purchased for blending of bitumen, totaling $435 million (2005 – $330 million), which are not included in the transportation and selling per unit calculations.

Foster Creek/Christina Lake crude oil per unit operating costs for 2006 increased 13 percent or $1.44 per bbl mainly due to workovers at Foster Creek, the higher U.S./Canadian dollar, increased electricity rates, chemicals, repair and maintenance and increased industry activity.

Foster Creek/Christina Lake depreciation, depletion and amortization

EnCana uses full cost accounting and calculates DD&A on a country-by-country cost centre basis. Accordingly, the DD&A rate for Canada and Foster Creek/Christina Lake are the same.

2007 versus 2006

Foster Creek/Christina Lake DD&A expenses of $125 million in 2007 decreased $32 million or 20 percent compared to 2006 due to:

- Production volumes decreased 37 percent; offset partially by
- Unit of production DD&A rates were higher than 2006 primarily as a result of increased future development costs and the higher U.S./Canadian dollar exchange rate.

2006 versus 2005

Foster Creek/Christina Lake DD&A expenses of $157 million in 2006 increased $41 million or 35 percent compared to 2005 due to:

- Production volumes increased 24 percent; and
- Unit of production DD&A rates were higher than 2005 as a result of the higher U.S./Canadian dollar exchange rate and an increase in future development costs.

Downstream operations

Financial Results ($ millions)	2007
Revenues	**$ 7,315**
Expenses	
Operating	**428**
Purchased product	**5,813**
Operating Cash Flow	**$ 1,074**

The downstream business commenced on January 2, 2007 when EnCana became a 50 percent partner in the entity that owns the Wood River and Borger refineries operated by ConocoPhillips.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). In July 2007, a new coker with a capacity of approximately 25,000 bbls/d was brought into service along with a new vacuum unit and revamped gas oil and distillate hydrotreaters.

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis). In early 2007, the refinery completed the construction and start-up of a facility utilizing proprietary sulphur removal technology for the production of low sulphur gasoline.

The goal of Borger and Wood River refineries are to refine approximately 275,000 bbls/d of bitumen (on a 100 percent basis) by 2015 to primarily motor fuels. Currently, the refineries have processing capability to refine up to approximately 70,000 bbls/d of bitumen.

Revenues reflect EnCana's 50 percent share of the sale of refined petroleum products in the U.S. Operating Cash Flow during 2007 benefited from strong refining margins as evidenced by the Chicago 3-2-1 Crack Spread, which is disclosed in the Business Environment section of this MD&A. The Chicago 3-2-1 Crack Spread increased 32 percent to $17.67 per bbl compared to $13.38 per bbl in 2006. On a 100 percent basis, the two refineries have a combined crude oil refining capacity of 452,000 bbls/d and operated at an average 96 percent of that capacity during 2007. Refined products averaged 457,000 bbls/d through 2007.

Purchased products, consisting mainly of crude oil, represented 93 percent of total expenses in 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses for 2007.

Downstream refining DD&A was $159 million in 2007 with no comparative amount in 2006.

MARKET OPTIMIZATION

Financial Results
($ millions)

	2007	2006	2005
Revenues	**$ 2,944**	$ 3,007	$ 4,267
Expenses			
Transportation and selling	**10**	16	13
Operating	**37**	62	85
Purchased product	**2,858**	2,862	4,159
Operating Cash Flow	**39**	67	10
Depreciation, depletion and amortization	**17**	12	8
Segment Income	**$ 22**	$ 55	$ 2

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

On January 1, 2006, EnCana adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty on a net basis in the Consolidated Statement of Earnings. This change was adopted prospectively and has no effect on the earnings of the reported periods. These purchases and sales are used to optimize transportation or fulfill marketing arrangements. As a result of the adoption of this policy, reported revenues and purchased product costs for 2007 included offsets of $3,863 million (2006 – $3,238 million; 2005 – nil).

2007 versus 2006

Revenues and purchased products were basically flat in 2007 compared with 2006, with slight decreases in prices being offset by increases in volumes required for optimization activities.

2006 versus 2005

Purchased product and revenues before the EITF 04-13 netting increased in 2006 due to third party purchases and sales as a result of the sale of the Empress NGL plant to a third party at the end of 2005. For 2006, this incremental activity to facilitate the movement of EnCana gas through the Empress plant totaled approximately $1.9 billion. This was offset by the EITF 04-13 netting which was applied prospectively for 2006 and was not applied to the 2005 values.

CORPORATE

Financial Results
($ millions)

	2007	2006	2005
Revenues	**$ (1,239)**	$ 2,050	$ (466)
Expenses			
Operating	**(5)**	(12)	2
Depreciation, depletion and amortization	**92**	75	73
Segment Income (Loss)	**$ (1,326)**	$ 1,987	$ (541)

Revenues represent unrealized mark-to-market gains or losses related to financial natural gas and crude oil hedge contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements.

Consolidated Corporate Expenses

($ millions)	2007	2006	2005
Administrative	**$ 384**	$ 271	$ 268
Interest, net	**428**	396	524
Accretion of asset retirement obligation	**64**	50	37
Foreign exchange (gain) loss, net	**(164)**	14	(24)
Stock-based compensation – options	**—**	—	15
(Gain) loss on divestitures	**(65)**	(323)	—

2007 versus 2006

Administrative expenses increased $113 million in 2007 compared to 2006 primarily due to higher long-term compensation expenses of $56 million as a result of the increase in the EnCana share price. The higher U.S./Canadian dollar exchange rate added an additional $18 million and the remaining increase was due to increased staff levels, higher salaries, and other related expenses. Administrative expenses in 2007 were $0.24 per Mcfe compared with $0.17 per Mcfe in 2006. Fourth quarter administrative expenses increased $37 million in 2007 compared to 2006 primarily due to higher long-term compensation expenses of $23 million and increased costs of $13 million due to the higher U.S./Canadian dollar exchange rate.

Net interest expense in 2007 increased $32 million from 2006 primarily as a result of higher average outstanding debt. EnCana's total long-term debt, including current portion, increased $2,709 million to $9,543 million at December 31, 2007 compared with $6,834 million at December 31, 2006. EnCana's 2007 weighted average interest rate on outstanding debt was 5.6 percent compared to 5.7 percent in 2006.

The foreign exchange gain of $164 million in 2007 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and settlement of foreign denominated intercompany transactions offset by revaluation of the partnership contribution receivable. Fourth quarter 2007 foreign exchange gain of $233 million is primarily due to the effects of the U.S./Canadian dollar exchange rate on settlement of foreign currency denominated intercompany transactions.

The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad and assets in Australia. The gain on divestitures in 2006 relates to the divestitures of the Chinook heavy oil discovery offshore Brazil and the Entrega Pipeline.

2006 versus 2005

Administrative expenses in 2006 were comparable with 2005 due to increases for office expenses, the higher U.S./Canadian dollar exchange rate and increased general costs offset by lower long-term compensation expenses, which were tied to EnCana's Common Share price. Administrative expenses in 2006 were $0.17 per Mcfe compared with $0.18 per Mcfe in 2005.

Interest expense in 2006 decreased by $128 million mainly as a result of a $121 million one time charge incurred in 2005 to retire certain medium term notes and lower average outstanding debt in 2006 due to repayments using the sales proceeds from the Entrega Pipeline, Ecuador, Brazil and gas storage divestitures.

Summary of Unrealized Mark-to-Market Gains (Losses) from Continuing Operations

($ millions)	2007	2006	2005
Revenues			
Natural Gas	$ (1,049)	$ 1,910	$ (494)
Crude Oil	(190)	140	28
	(1,239)	2,050	(466)
Expenses	(4)	(10)	3
	(1,235)	2,060	(469)
Income Tax Expense (Recovery)	(424)	703	(158)
Unrealized Mark-to-Market Gains (Losses), after-tax	$ (811)	$ 1,357	$ (311)

Price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 18 to the Consolidated Financial Statements.

Income tax

2007 versus 2006

The effective tax rate for 2007 was 19.4 percent compared to 27.3 percent in 2006. The 2007 rate reflects the effect of a Canadian federal corporate tax legislative change ($179 million) and a reduction in the Canadian federal corporate tax rate ($301 million). The legislative change relates to phase in of the deductibility of Crown royalties which is now complete and will not recur in the future. The Canadian federal tax rate is to be reduced from 19.5 percent to 15 percent between 2008 and 2012. The 2006 effective rate also reflects the effect of reductions in the Canadian federal and Alberta corporate tax rates ($457 million).

Cash taxes were $1,554 million in 2007 compared to $942 million in 2006. The largest component of the increase of $612 million is $519 million of higher U.S. taxes in 2007 offset by the cash tax benefit of the legislative change ($179 million) referred to above. The increase in U.S. tax is due to the cash flows from U.S. downstream refinery operations and increased income from U.S. upstream operations.

2006 versus 2005

The effective tax rate for 2006 was 27.3 percent compared to 30.8 percent for 2005. The decrease was largely due to a decrease in future income tax expense of $457 million as a result of reductions in the Canadian federal and Alberta corporate tax rates, which were enacted in the second quarter of 2006.

Cash taxes excluding cash taxes related to divestitures were $893 million in 2006 compared to $626 million in 2005. The increase in cash tax expense over 2005 primarily reflects higher Canadian income resulting from higher prices in 2005, which was recognized for income tax purposes in 2006. An additional $49 million of cash tax was incurred in 2006, resulting from the divestiture of certain assets in Brazil, compared to $578 million of cash tax in the second quarter of 2005 as a result of the divestiture of the Gulf of Mexico operations. These amounts are included in investing activities in the Consolidated Statement of Cash Flows.

Further information regarding EnCana's effective tax rate can be found in Note 9 to the Consolidated Financial Statements. EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings, which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset divestitures where the tax values of the assets sold differ from their accounting values;
- Adjustments for changes to tax rates and other tax legislation, which have an impact on future income tax obligations;
- The non-taxable half of Canadian capital gains or losses; and
- Items where the income tax treatment is different from the accounting treatment.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

NET CAPITAL INVESTMENT

Capital Summary
($ millions)

	2007	2006	2005
Canada	**$ 3,330**	$ 3,352	$ 3,702
United States	**1,919**	2,061	1,982
Other	**106**	106	125
Integrated Oil	**580**	632	393
Market Optimization	**6**	44	197
Corporate	**94**	74	78
Total Capital Investment	**6,035**	6,269	6,477
Acquisitions	**2,702**	331	448
Divestitures	**(481)**	(689)	(2,523)
Discontinued Operations	**—**	(2,647)	(305)
Net Capital Investment	**$ 8,256**	$ 3,264	$ 4,097

EnCana's Total Capital Investment for the year ended December 31, 2007 was funded by Cash Flow and debt.

2007 versus 2006

Capital investment during 2007 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil processing capacity through its joint venture with ConocoPhillips. As disclosed in the Foreign Exchange section of this MD&A, capital expenditures were also influenced by the rise in the average U.S./Canadian dollar exchange rate and increased Total Capital Investment by $199 million.

The $164 million decrease in Canada and United States capital investment in 2007 compared to 2006 was primarily due to:

- Canada capital investment of $3,330 million in 2007 decreased $22 million primarily due to:
  - Drilling and completion costs decreased due to increased efficiencies through the use of fit-for-purpose rigs. In addition, the Company drilled a larger number of lower cost wells in the Shallow Gas and CBM key resource plays. In Canada, the Company drilled 3,810 net wells in 2007 or 27 percent more compared to 3,001 net wells in 2006;
  - Facility costs decreased $204 million or 19 percent mainly due to higher costs in 2006 resulting from the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn, respectively; and
  - Offsetting the decreases in capital expenditures was the rise in the average U.S./Canadian dollar exchange rate which increased Canada capital by $168 million.
- U.S. capital investment decreased $142 million to $1,919 million primarily due to lower drilling and completion costs resulting from increased efficiencies through the use of additional fit-for-purpose rigs. EnCana employed an average of 22 fit-for-purpose rigs during 2007 compared to 5 during 2006. The number of net wells drilled increased slightly to 644 from 639 in 2006.

2006 versus 2005

Capital investment during 2006 was primarily focused on continued development of EnCana's North American key resource plays. Natural gas capital expenditures were focused on continued development of the Company's key resource plays in Cutbank Ridge and Bighorn in Canada and Piceance, Jonah, East Texas and Fort Worth in the U.S. Crude oil capital spending in 2006 was concentrated on expansion of the Company's steam-assisted gravity drainage ("SAGD") projects located at Foster Creek and Christina Lake and developing the new resource play at Borealis.

The $32 million decrease in Canada, United States and Integrated Oil capital investment in 2006 was primarily due to:

- Canada and Integrated Oil capital investment decreased $366 million offset by an increase in foreign exchange of $255 million for a net reported decrease of $111 million. The overall decrease was due to:
  - Crown land sales and other land costs were $260 million or 68 percent lower than the prior year mainly due to large land purchases in 2005;
  - Drilling and completion costs decreased $307 million or 13 percent due to a decrease in the total number of wells drilled compared to 2005;
  - Facility costs increased $199 million or 16 percent mainly due to the costs resulting from the continued expansion of Foster Creek and Christina Lake facilities and the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn, respectively; and
  - In Canada, the Company drilled 3,009 net wells (Canada – 3,001; Integrated Oil – 8) in 2006 compared to 4,038 net wells (Canada – 3,999; Integrated Oil – 39) in 2005. The decrease resulted from the Company's decision to decrease drilling activity in response to higher industry costs and new regulations related to CBM water well testing, which delayed drilling. In various locations, the Company redirected capital spending to recompletion and tie-in of existing wells instead of drilling new wells in the current price environment.
- U.S. capital investment increased $79 million to $2,061 million primarily due to additional drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah after receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells in the Deep Bossier play in East Texas. The number of net wells drilled increased slightly to 639 from 617 in 2005.

Integrated Oil Capital Investment

Capital investment during 2007 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on capacity maintenance and bitumen expansion projects at the Wood River and Borger refineries.

Market Optimization Capital Investment

Expenditures in 2006 and 2005 were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

Corporate Capital Investment

Corporate capital investment in 2007 and 2006 included land purchases and costs related to the development of a Calgary office complex. On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of certain project assets and entered into a 25 year lease agreement with a third party developer. In addition, capital investment has been directed to business information systems and leasehold improvements.

Acquisitions, Divestitures and Discontinued Operations

Acquisitions in 2007 included the purchase of interests in the Deep Bossier play in East Texas. EnCana acquired all of the Deep Bossier natural gas and land interests of privately owned Leor Energy group in East Texas for approximately $2.55 billion before closing adjustments, increasing EnCana's interest to 100 percent in these lands. Acquisitions in 2006 were comprised of minor property acquisitions.

Divestitures in 2007 primarily included the sale of assets in Australia, assets in the Mackenzie Delta and Beaufort Sea, interests in Chad and The Bow office project assets. In 2006, divestitures included the sale of interests in the Chinook heavy oil discovery offshore Brazil and the Entrega Pipeline in Colorado.

Included in Discontinued Operations in 2006 is the divestiture of EnCana's Ecuador assets and gas storage business (discussed in Note 5 to the Consolidated Financial Statements) with the proceeds reduced by capital spending prior to the sale.

Proved Oil and Gas Reserves

Proved Reserves by Country
Constant Prices After Royalties

As at December 31	Natural Gas (billions of cubic feet) 2007	2006	2005	Crude Oil and NGLs (1) (millions of barrels) 2007	2006	2005
Canada (2)	**7,292**	7,028	6,517	**868.9**	1,079.4	932.5
United States	**6,008**	5,390	5,267	**58.3**	54.0	53.1
Ecuador	**—**	—	—	**—**	—	135.0
Total	**13,300**	12,418	11,784	**927.2**	1,133.4	1,120.6

(1) Crude Oil and NGLs include condensate.
(2) Includes Foster Creek/Christina Lake.

Each year, EnCana engages independent qualified reserves evaluators to prepare reports on 100 percent of the Company's oil and natural gas reserves. The Company has a Reserves Committee of independent Board members, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Committee also reviews the procedures for providing information to the evaluators. EnCana's disclosure of reserves data is covered by National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and U.S. Financial Accounting Standards Board ("FASB") reserves reporting requirements. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case, December 31, 2007.

Proved Reserves Reconciliation by Country
Constant Prices After Royalties

As at December 31, 2007	Natural Gas (billions of cubic feet) Canada	USA	Total	Crude Oil and NGLs (1) (millions of barrels) Canada (2)	USA	Total
Beginning of year	7,028	5,390	12,418	1,079.4	54.0	1,133.4
FCCL Partnership contribution (2)	—	—	—	(398.0)	—	(398.0)
Effective Jan 2, 2007	7,028	5,390	12,418	681.4	54.0	735.4
Revisions and improved recovery	87	78	165	75.5	3.6	79.1
Extensions and discoveries	949	827	1,776	155.8	5.9	161.7
Acquisitions	63	211	274	0.2	—	0.2
Divestitures	(24)	(7)	(31)	(0.2)	—	(0.2)
Production	(811)	(491)	(1,302)	(43.8)	(5.2)	(49.0)
End of year	**7,292**	**6,008**	**13,300**	**868.9**	**58.3**	**927.2**

(1) Crude Oil and NGLs include condensate.
(2) Effective January 2, 2007, the Company's Foster Creek and Christina Lake operations were contributed to a 50/50 upstream partnership with ConocoPhillips. The Company's ownership in reserves associated with these properties were reduced by 398 million barrels.

Natural Gas

EnCana's proved natural gas reserves at December 31, 2007 totaled 13,300 Bcf. Approximately 170 percent of production was replaced by reserves additions during 2007. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 1,776 Bcf. Positive revisions of 165 Bcf were 1 percent of natural gas reserves at the beginning of 2007. In Canada, positive revisions of 87 Bcf (or 1 percent of the opening balance) were largely associated with the Cutbank Ridge and Shallow Gas key resource plays. Upward revisions in the U.S. amounted to 78 Bcf (or 1 percent of the opening balance), mainly due to better performance in the Jonah key resource play. In total, EnCana's key resource plays accounted for over 80 percent of extensions and discoveries. Acquisitions net of divestitures account for approximately 2 percent of the opening natural gas reserves balance. The Leor transaction accounted for 75 percent of additions via acquisitions in 2007.

Crude Oil and NGLs

EnCana's proved crude oil and NGLs reserves at December 31, 2007 totaled 927 MMbbls. Approximately 490 percent of production was replaced by reserves additions during 2007, post the contribution to the FCCL Partnership. Extensions and discoveries amounted to 162 MMbbls, while revisions were positive 79 MMbbls (or 7 percent of the opening balance). Christina Lake accounted for approximately 140 MMbbls or more than 85 percent of extensions and discoveries. Foster Creek accounted for approximately 60 MMbbls or 75 percent of positive revisions, due to an expanded resource base. Reserves changes due to acquisitions and divestitures in continuing operations during 2007 were not significant. With the creation of the integrated oil business, effective January 2, 2007, ConocoPhillips and EnCana each own a 50 percent interest in the Foster Creek and Christina Lake upstream operations and the Wood River and Borger refineries. As a result of this transaction, the Company's estimated proved oil reserves were reduced by 398 MMbbls.

EnCana continues to evaluate the impact of the Alberta Government's new Alberta Royalty Framework on the Company's proved oil and gas reserves.

Discontinued Operations

In keeping with EnCana's North American resource play and refining operations strategy, the Company has made a number of divestitures over the years that are accounted for as discontinued operations. EnCana's 2007 Net Earnings from Discontinued Operations were $75 million (2006 – $601 million; 2005 – $597 million).

MIDSTREAM

The $75 million gain on discontinuance in 2007 is the result of an expired obligation included in the December 2005 sale of the Company's Midstream NGLs processing operations. The obligation provided potential market price support, which was not used for the facilities and was accrued for in 2005.

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the U.S. Total proceeds received were approximately $1.5 billion and an after-tax gain on sale of $829 million was recorded.

On December 13, 2005, EnCana completed the sale of its NGLs processing operations for proceeds of $625 million and recorded an after-tax gain on sale of $370 million.

ECUADOR

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of $1.4 billion before indemnifications. A loss of $279 million, including the impact of indemnifications, was recorded.

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount calculated in accordance with the terms of the agreements, approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

Amounts recorded as DD&A in 2006 and 2005 represent provisions that were recorded against the net book value of the Ecuador operations to recognize Management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian GAAP.

Additional information on discontinued operations can be found in Note 5 to the Consolidated Financial Statements.

Liquidity and Capital Resources

($ millions)	2007	2006	2005
Net cash provided by (used in)			
Operating activities	**$ 8,429**	$ 7,973	$ 7,430
Investing activities	**(8,175)**	(3,382)	(4,520)
Financing activities	**(119)**	(4,294)	(3,396)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**16**	—	(2)
Increase (decrease) in cash and cash equivalents	**$ 151**	$ 297	$ (488)

OPERATING ACTIVITIES

Cash Flow from Continuing Operations was $8,453 million in 2007 compared to $7,043 million in 2006. Reasons for this increase are discussed under the Cash Flow section of this MD&A.

INVESTING ACTIVITIES

Net cash used for investing activities in 2007 increased $4,793 million compared to 2006. The 2006 investing activities include proceeds received from divestitures of the Ecuador assets ($1.4 billion) and the gas storage business ($1.5 billion). Capital expenditures, including property acquisitions, in 2007 increased $2,137 million compared to 2006 primarily due to the Deep Bossier acquisition, offsetting otherwise lower capital expenditures.

FINANCING ACTIVITIES

Net issuance of long-term debt in 2007 was $2,333 million compared to net issuance of $61 million in 2006. EnCana's debt adjusted for working capital ("net debt") was $10,726 million as at December 31, 2007 compared with $6,566 million as at December 31, 2006. EnCana maintains numerous capital resources including committed bank credit facilities and shelf prospectuses.

On March 12, 2007, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$500 million. The notes have a coupon rate of 4.3 percent and mature on March 12, 2012. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

On May 24, 2007, EnCana filed a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. The shelf prospectus replaces EnCana's C$1.0 billion shelf prospectus which was fully drawn.

On August 13, 2007, EnCana completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of $500 million. The notes have a coupon rate of 6.625 percent and mature on August 15, 2037. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

On December 4, 2007, EnCana completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of $1.5 billion in two series. The first series of $700 million have a coupon rate of 5.90 percent and mature on December 1, 2017. The second series of $800 million have a coupon rate of 6.50 percent and mature on February 1, 2038. The net proceeds of the offering were used to repay a portion of the credit facilities used to acquire the Deep Bossier natural gas and land interests in East Texas.

As at December 31, 2007, EnCana had available unused committed bank credit facilities in the amount of $3.2 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $4.0 billion.

Subsequent to year end, on January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's Ratings Service has assigned a rating of A- with a "Stable" outlook, DBRS Limited has assigned a rating of A(low) with a "Stable" trend and Moody's Investors Service has assigned a rating of Baa2 with a "Positive" outlook.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under six consecutive NCIBs. During 2007, EnCana purchased 38.9 million of its Common Shares for total consideration of $2,025 million compared with 85.6 million Common Shares for total consideration of $4,219 million in 2006. As of December 31, 2007, the number of Common Shares that EnCana will be permitted to purchase in 2008 under the current NCIB is 75.1 million. During January 2008, EnCana purchased 3.0 million Common Shares under the NCIB for total consideration of $191 million.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. EnCana doubled its quarterly dividend to 20 cents per share in the first quarter of 2007 and payments for 2007 totaled $603 million compared with $304 million in 2006. These dividends were funded by Cash Flow. Consistent with the Company's focus on shareholder value creation, EnCana's Board of Directors intends to double the quarterly dividend in 2008 to $0.40 per share. On February 13, 2008, the Company's Board of Directors declared a dividend for the first quarter of 2008 in the amount of $0.40 per share.

Financial Metrics	2007	2006	2005
Net Debt to Capitalization (1)	**34%**	27%	33%
Net Debt to Adjusted EBITDA (2)	**1.2x**	0.6x	1.1x

(1) Net Debt is a non-GAAP measure defined as Long-Term Debt plus Current Liabilities less Current Assets. Capitalization is a non-GAAP measure defined as Net Debt plus Shareholders' Equity.

(2) Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gain on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Net Debt to Capitalization and Net Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. The Net Debt to Capitalization ratio is higher compared to December 31, 2006 as a result of higher net debt primarily due to the Deep Bossier acquisition.

Free Cash Flow

EnCana's 2007 Free Cash Flow increased $1,526 million compared to 2006, which resulted from a combination of increased total Cash Flow and reduced total capital investment.

($ millions)	2007	2006	2005
Cash Flow (1)	**$ 8,453**	$ 7,161	$ 7,426
Total Capital Investment	**6,035**	6,269	6,477
Free Cash Flow (2)	**$ 2,418**	$ 892	$ 949

(1) Cash Flow is a non-GAAP measure and is defined under the "Cash Flow" section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Total Capital Investment and is used by Management to determine the funds available for other investing and/or financing activities.

Outstanding Share Data

(millions)	2007	2006	2005
Common Shares outstanding, beginning of year	**777.9**	854.9	900.6
Common Shares issued under option plans	**8.3**	8.6	15.0
Common Shares purchased	**(36.0)**	(85.6)	(60.7)
Common Shares outstanding, end of year	**750.2**	777.9	854.9
Weighted average Common Shares outstanding – diluted	**764.6**	836.5	889.2

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at December 31, 2007 and 2006.

Employees and directors have been granted options to purchase Common Shares under various plans. At December 31, 2007, approximately 3.4 million options without Tandem Share Appreciation Rights ("TSAR") attached were outstanding, all of which are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Stock options granted after December 31, 2003 have an associated TSAR attached and employees may elect to exercise either the stock option or the associated Share Appreciation Right ("SAR"). Stock option exercises result in the issuance of new Common Shares while TSAR exercises result in cash payments by the Company. PSUs will not result in the issuance of new Common Shares by the Company as shares are purchased through a trust for payment, should performance considerations be met. In 2007, vesting provisions for the PSUs granted in 2004 were met and the Company distributed 2.9 million shares from the trust. At December 31, 2007, there were approximately 2.6 million shares held in trust for distribution upon vesting of outstanding PSUs.

Contractual Obligations and Contingencies

Contractual Obligations (1)

($ millions)	2008	2009 to 2010	2011 to 2012	2013+	Total
	Expected Payment Date				
Long-Term Debt (2)	$ 703	$ 450	$ 3,007	$ 5,400	**$ 9,560**
Partnership Contribution Payable (3)	288	631	711	1,821	**3,451**
Asset Retirement Obligation	166	62	73	7,094	**7,395**
Pipeline Transportation	527	933	902	2,222	**4,584**
Purchase of Goods and Services	404	387	252	621	**1,664**
Product Purchases	24	48	23	98	**193**
Operating Leases (4)	70	152	419	3,402	**4,043**
Capital Commitments	54	13	133	39	**239**
Other Long-Term Commitments	18	16	3	1	**38**
Total	$ 2,254	$ 2,692	$ 5,523	$20,698	**$ 31,167**
Product Sales	$ 51	$ 96	$ 106	$ 244	**$ 497**
Partnership Contribution Receivable (3)	297	643	713	1,791	**3,444**

(1) In addition, the Company has made commitments related to its risk management program. See Note 18 to the Consolidated Financial Statements. The Company has an obligation to fund its Pension Plan and Other Post-Employment Benefits as disclosed in Note 17 to the Consolidated Financial Statements.

(2) Principal component only. See Note 14 to the Consolidated Financial Statements.

(3) Principal component only. See Note 10 to the Consolidated Financial Statements.

(4) Related to office space.

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana's total long-term debt commitments of $9,560 million at December 31, 2007 are $2,001 million in commitments related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. Further details regarding EnCana's long-term debt are described in Note 14 to the Consolidated Financial Statements.

As at December 31, 2007, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 111 Bcf at a weighted average price of $4.42 per Mcf. At December 31, 2007, these transactions had an unrealized loss of $309 million.

LEASES

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes.

DEEP PANUKE

In October 2007, EnCana received regulatory approval from the Canada-Nova Scotia Offshore Petroleum Board to develop the Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. Expected to start production in 2010, the $700 million project is expected to deliver between 200 MMcf/d and 300 MMcf/d to markets in Canada and the northeast U.S.

In late November 2007, EnCana signed a Letter of Agreement pertaining to the Production Facility Center ("PFC") for the Deep Panuke project. The agreement is for Single Buoy Moorings to construct a production facility that EnCana will lease upon delivery, expected in late 2010. EnCana also has the option to purchase the facility. EnCana has determined that it has substantially all the construction period risk and consequently is reporting the PFC as an asset under construction during the construction period. Once in service, the asset will be classified as a capital lease.

THE BOW

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company.

VARIABLE INTEREST ENTITIES ("VIEs")

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. Pursuant to the agreement with Brown Kilgore, EnCana operates the properties, receives all of the revenue and pays all of the expenses associated with the properties. The arrangement with Brown Kilgore will be complete on May 18, 2008 and the assets will be transferred to EnCana at that time. EnCana has determined that the relationship with Brown Kilgore represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Kilgore from the date of acquisition.

LEGAL PROCEEDINGS

EnCana is involved in various legal claims associated with the normal course of operations and believes it has made adequate provision for such legal claims.

DISCONTINUED MERCHANT ENERGY OPERATIONS

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payment, of $20.5 million and $2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against the outstanding claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

Accounting Policies and Estimates

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2007, the Company adopted the CICA Handbook Section 1530 “Comprehensive Income”, Section 3251 “Equity”, Section 3855 “Financial Instruments – Recognition and Measurement”, and Section 3865 “Hedges”. As required by the new standards, prior periods have not been restated, except to reclassify the foreign currency translation adjustment balance as described under Comprehensive Income.

The adoption of these standards has had no material impact on the Company’s net earnings or cash flows. The other effects of the implementation of the new standards are discussed below.

Comprehensive Income

The new standards introduce comprehensive income, which consists of net earnings and other comprehensive income (“OCI”). The Company’s Consolidated Financial Statements now include a Statement of Comprehensive Income, which includes the components of comprehensive income. For EnCana, OCI is currently comprised of the changes in the foreign currency translation adjustment balance.

The cumulative changes in OCI are included in accumulated other comprehensive income (“AOCI”), which is presented as a new category within shareholders’ equity in the Consolidated Balance Sheet. The accumulated foreign currency translation adjustment, formerly presented as a separate category within shareholders’ equity, is now included in AOCI. The Company’s Consolidated Financial Statements now include a Statement of Accumulated Other Comprehensive Income, which provides the continuity of the AOCI balance.

The adoption of comprehensive income has been made in accordance with the applicable transitional provisions. Accordingly, the December 31, 2007 period end accumulated foreign currency translation adjustment balance of $3,063 million is now included in AOCI (2006 – $1,375 million; 2005 – $1,262). In addition, the change in the accumulated foreign currency translation adjustment balance for the year ended December 31, 2007 of $1,688 million is now included in OCI in the Statement of Comprehensive Income (2006 – $113 million; 2005 – $226).

Financial Instruments

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. EnCana’s accounting policies for financial instruments are described in Note 1 to the Consolidated Financial Statements.

The adoption of the financial instruments standard has been made in accordance with its transitional provisions. Accordingly, at January 1, 2007, $52 million of other assets were reclassified to long-term debt to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt. The costs capitalized within long-term debt will be amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. The adoption of the effective interest method of amortization had no effect on opening retained earnings.

RECENT ACCOUNTING PRONOUNCEMENTS

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have an impact on the Company:

- As of January 1, 2008, EnCana will be required to adopt the CICA Handbook Section 3031 "Inventories", which will replace the existing inventories standard. The new standard requires inventory to be valued on a first-in, first-out or weighted average basis, which is consistent with EnCana's current treatment. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation", which will replace Section 3861 "Financial Instruments – Disclosure and Presentation". The new disclosure standard will increase EnCana's disclosure regarding the risks associated with financial instruments and how those risks are managed.
- As of January 1, 2008, EnCana will be required to adopt CICA Handbook Section 1535 "Capital Disclosures", which will require EnCana to disclose its objectives, policies and processes for managing capital.
- In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRSs"). In March 2007, the AcSB released an "Implementation Plan for Incorporating IFRSs into Canadian GAAP", which assumes a convergence date of January 1, 2011. Following a progress review, the AcSB is expected to confirm this date by March 31, 2008. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A summary of EnCana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in reserves estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property divestiture, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of EnCana's oil and gas reserves are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants, and refining facilities. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by EnCana for impairment at least annually. Goodwill was allocated to the business segments based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

Derivative Financial Instruments

Derivative financial instruments are used by EnCana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is to not use derivative financial instruments for speculative purposes.

The Company enters into financial transactions to help reduce its exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics. These transactions generally are swaps, collars, or options and are generally entered into with major financial institutions or commodities trading institutions.

EnCana may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of its total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

EnCana may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

EnCana also may purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from the Company's natural gas and crude oil financial derivatives are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators. In 2005, 2006, and 2007, the Company elected not to designate any of its current price risk management activities as accounting hedges and, accordingly, accounts for all derivatives using the mark-to-market accounting method.

Pensions and Other Post-Employment Benefits

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan. Pension costs are a component of compensation costs.

Performance Share Units and Performance Tandem Share Appreciation Rights

The PSU and Performance TSAR plans provide for a range of payouts, based on EnCana's performance relative to certain peers or key predetermined performance measures. EnCana expenses the cost of PSUs and Performance TSARs based on expected payouts; however, the amounts to be paid, if any, may vary from the current estimate. Further details on these plans are disclosed in Note 17 to the Consolidated Financial Statements.

Risk Management

EnCana's results are affected by:

- financial risks (including commodity price, foreign exchange, interest rate and credit risks);
- operational risks;
- environmental, health, safety and security risks; and
- reputational risks.

EnCana takes a proactive approach in the identification and management of risks that can affect the Company.

FINANCIAL RISKS

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial instrument agreements. The details of these instruments, including any unrealized gains or losses, as of December 31, 2007, are disclosed in Note 18 to the Consolidated Financial Statements.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps or options, which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Commodity price

To partially mitigate the natural gas commodity price risk, the Company enters into swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

EnCana has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $12 million at December 31, 2007.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for approximately 17 percent of its expected 2008 oil production with fixed price swaps and put options.

To manage its electricity consumption costs, EnCana has entered into two derivative contracts for a term of 11 years, commencing January 1, 2007.

Foreign exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian dollar exchange rate, EnCana may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

EnCana also maintains a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest rates

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana has entered into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

Credit risk

EnCana is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality and transactions that are fully collateralized. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry.

OPERATIONAL RISKS

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

EnCana also partially mitigates operational risks by maintaining a comprehensive insurance program.

Alberta royalty framework

On October 25, 2007, the Alberta Government announced a new Alberta Royalty Framework ("ARF"). The ARF establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. The changes introduced by the ARF are to be effective January 1, 2009.

The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software by the Alberta Government to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. There may be modifications introduced to the ARF prior to the implementation thereof.

ENVIRONMENT, HEALTH, SAFETY AND SECURITY RISKS

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to Senior Management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors provides recommended environmental policies for approval by EnCana's Board of Directors and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to protect EnCana's personnel and assets. EnCana has an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations, accounting or internal control matters.

Climate change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants, and it is anticipated that other jurisdictions will announce emissions reduction plans in the future.

The Canadian Federal Government has announced its intention to regulate greenhouse gases and other air pollutants. It is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce GHG emissions by 20 percent by 2020, and a commitment to regulate industry on an emissions intensity basis in the short term. Currently there are few technical details regarding the implementation of the government's plan, but they have made a commitment to work with industry to develop the specifics.

In March 2007, the Alberta Government amended the Climate Change and Emissions Management Act ("CCEMA") requiring facilities that emit more than 100,000 tonnes of GHG per year to reduce their emissions intensity by 12 percent from a regulated baseline starting on July 1, 2007. The companies that operate these facilities have options to comply with this requirement including making operating improvements, buying offsets to apply against their emission total or making contributions at C$15/tonne to an Alberta Climate Change and Emissions Management Fund. EnCana has submitted its baseline data for the covered facilities per the regulation and will be submitting its first compliance report by March 31, 2008. This requirement is not expected to have a material impact.

On February 13, 2007 British Columbia announced a target to reduce provincial greenhouse gas emissions by 33 percent below current levels by 2020 and enacted this target into law through the Greenhouse Gas Reduction Targets Act released on November 20, 2007. EnCana is monitoring these developments and is in the process of working with the province on the emerging regulations.

As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with Governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on the following key elements:

- our significant weighting in natural gas;
- our recognition as an industry leader in CO_2 sequestration;
- our focus on energy efficiency and the development of technology to reduce GHG emissions;
- our involvement in the creation of industry best practices; and
- our industry leading steam to oil ratio, which translates directly into lower emissions intensity.

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is comprised of three principal elements:

1. Manage Existing Costs When regulations are implemented a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.
2. Respond to Price Signals As regulatory regimes for GHGs develop in the jurisdictions where we work inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, where appropriate, EnCana is also attempting to realize the associated value of its reduction projects.
3. Anticipate Future Carbon Constrained Scenarios EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios inform our long range planning and our analyses on the implications of regulatory trends.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on our website at **www.encana.com.**

REPUTATIONAL RISKS

EnCana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting, or with the potential to affect, EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

Outlook

EnCana plans to continue to focus principally on growing natural gas and crude oil production from unconventional resource plays in North America and on developing its high quality in-situ oil resources and expanding the Company's downstream heavy oil processing capacity through its joint venture with ConocoPhillips.

Volatility in crude oil prices is expected to continue throughout 2008 as a result of market uncertainties over supply and refining disruptions, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. Canadian crude prices will face added uncertainty due to the risk of refinery disruptions in an already tight U.S. Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked and that unconventional resource plays can offset conventional gas production declines over the next few years. Past this period, the industry's ability to continue to grow gas supply is expected to be challenged in North America by land access and regulatory issues.

The Company expects its 2008 capital investment program to be funded from Cash Flow and debt.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on EnCana's 2008 results is available in the Corporate Guidance on our website at **www.encana.com**. EnCana's news release dated February 14, 2008 and financial statements are available on www.sedar.com.

Advisory

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: potential well and drilling inventories; future economic performance; oil, gas and NGLs production and sales estimates for 2008 and beyond; projections of CAGR, cash flow, free cash flow and dividends which may be paid in the future; potential share purchases under the Company's Normal Course Issuer Bid; projections of future internal rates of return expected from the Company's projects; projections of future drilling, completion and tie-in costs; the potential impact of the implementation of the new Alberta Royalty Framework on EnCana's financial condition and projected 2008 capital investments; the expected timing of, and closing of, the sale of the Company's interests in Brazil; projections with respect to growth of natural gas production from unconventional resource plays and in-situ oil resources, including the expansion of in-situ oil production through 2015; projected results which may be achieved through the use of a solvent aided process in the Company's SAGD operations, including potential operating cost reductions and recovery rate increases; the expansion of the Company's downstream heavy oil processing capacity; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2008 and beyond and the reasons therefor; the Company's projected capital investment levels for 2008 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the climate change initiatives on future operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to offset future conventional gas production declines over the next few years. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current corporate guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101"). The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, Natural Gas Liquids and Natural Gas Conversions

In this document, certain crude oil and natural gas liquids ("NGLs") volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play and Estimated Ultimate Recovery

EnCana uses the terms resource play and estimated ultimate recovery. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

CURRENCY AND NON-GAAP MEASURES

All information included in this document, Management's Discussion and Analysis and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $1.00 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Free Cash Flow, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Adjusted EBITDA and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in Management's Discussion and Analysis dated February 21, 2008 contained in the Company's 2008 Annual Report.

DIFFERENCES IN ENCANA'S CORPORATE GOVERNANCE PRACTICES COMPARED TO NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the New York Stock Exchange ("NYSE"), EnCana is not required to comply with most of the NYSE Corporate Governance Standards and instead may comply with Canadian Corporate Governance Practices. EnCana is, however, required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. companies listed on the NYSE under NYSE corporate governance standards. A summary of these significant differences is available on EnCana's website (www.encana.com). Except as described in this document, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at **www.encana.com**.

Management Report

Management's Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of EnCana Corporation (the "Company") are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

The Company's Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets at least on a quarterly basis.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2007. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting. Based on our evaluation, Management has concluded that the Company's internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2007, as stated in their Auditor's Report. PricewaterhouseCoopers LLP has provided such opinions.

Randall K. Eresman
President &
Chief Executive Officer

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

February 21, 2008

Auditors’ Report

To the Shareholders of EnCana Corporation

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of EnCana Corporation as of December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnCana Corporation as at December 31, 2007 and December 31, 2006, and the related consolidated statements of earnings, retained earnings, comprehensive income, accumulated other comprehensive income, and cash flows for each of the years in the three year period ended December 31, 2007. 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 the Company’s financial statements as at December 31, 2007 and December 31, 2006 and for each of the years then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company’s financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes 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.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited EnCana Corporation’s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company’s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 21, 2008

Consolidated Statement of Earnings

For the years ended December 31 (US$ millions, except per share amounts)		2007	2006	2005
Revenues, Net of Royalties	(Note 4)			
Upstream		**$ 11,758**	$ 10,369	$ 10,218
Integrated Oil		**7,983**	973	554
Market Optimization		**2,944**	3,007	4,267
Corporate – Unrealized gain (loss) on risk management	(Note 18)	**(1,239)**	2,050	(466)
		21,446	16,399	14,573
Expenses	(Note 4)			
Production and mineral taxes		**291**	349	453
Transportation and selling		**1,010**	1,070	845
Operating		**2,278**	1,655	1,438
Purchased product		**8,583**	2,862	4,159
Depreciation, depletion and amortization		**3,816**	3,112	2,769
Administrative		**384**	271	268
Interest, net	(Note 7)	**428**	396	524
Accretion of asset retirement obligation	(Note 15)	**64**	50	37
Foreign exchange (gain) loss, net	(Note 8)	**(164)**	14	(24)
Stock-based compensation – options	(Note 16)	**—**	—	15
(Gain) loss on divestitures	(Note 6)	**(65)**	(323)	—
		16,625	9,456	10,484
Net Earnings Before Income Tax		**4,821**	6,943	4,089
Income tax expense	(Note 9)	**937**	1,892	1,260
Net Earnings From Continuing Operations		**3,884**	5,051	2,829
Net Earnings From Discontinued Operations	(Note 5)	**75**	601	597
Net Earnings		**$ 3,959**	$ 5,652	$ 3,426
Net Earnings From Continuing Operations per Common Share	(Note 19)			
Basic		**$ 5.13**	$ 6.16	$ 3.26
Diluted		**$ 5.08**	$ 6.04	$ 3.18
Net Earnings per Common Share	(Note 19)			
Basic		**$ 5.23**	$ 6.89	$ 3.95
Diluted		**$ 5.18**	$ 6.76	$ 3.85

See accompanying Notes to Consolidated Financial Statements

Consolidated Statement of Retained Earnings

For the years ended December 31 (US$ millions)		2007	2006	2005
Retained Earnings, Beginning of Year		**$11,344**	$ 9,481	$ 7,935
Net Earnings		**3,959**	5,652	3,426
Dividends on Common Shares		**(603)**	(304)	(238)
Charges for Normal Course Issuer Bid	(Note 16)	**(1,618)**	(3,485)	(1,642)
Retained Earnings, End of Year		**$13,082**	$11,344	$ 9,481

Consolidated Statement of Comprehensive Income

For the years ended December 31 (US$ millions)	2007	2006	2005
Net Earnings	**$ 3,959**	$ 5,652	$ 3,426
Other Comprehensive Income, Net of Tax			
Foreign Currency Translation Adjustment	**1,688**	113	226
Comprehensive Income	**$ 5,647**	$ 5,765	$ 3,652

Consolidated Statement of Accumulated Other Comprehensive Income

For the years ended December 31 (US$ millions)	2007	2006	2005
Accumulated Other Comprehensive Income, Beginning of Year	**$ 1,375**	$ 1,262	$ 1,036
Foreign Currency Translation Adjustment	**1,688**	113	226
Accumulated Other Comprehensive Income, End of Year	**$ 3,063**	$ 1,375	$ 1,262

See accompanying Notes to Consolidated Financial Statements

Consolidated Balance Sheet

As at December 31 (US$ millions)		2007	2006
Assets			
Current Assets			
Cash and cash equivalents		$ 553	$ 402
Accounts receivable and accrued revenues		2,381	1,721
Current portion of partnership contribution receivable	(Notes 3, 10)	297	—
Risk management	(Note 18)	385	1,403
Inventories	(Note 11)	828	176
		4,444	3,702
Property, Plant and Equipment, net	(Notes 4, 12)	35,865	28,213
Investments and Other Assets	(Note 13)	607	533
Partnership Contribution Receivable	(Notes 3, 10)	3,147	—
Risk Management	(Note 18)	18	133
Goodwill	(Note 4)	2,893	2,525
	(Note 4)	$46,974	$35,106
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		$ 3,982	$ 2,494
Income tax payable		1,150	926
Current portion of partnership contribution payable	(Notes 3, 10)	288	—
Risk management	(Note 18)	207	14
Current portion of long-term debt	(Note 14)	703	257
		6,330	3,691
Long-Term Debt	(Note 14)	8,840	6,577
Other Liabilities		242	79
Partnership Contribution Payable	(Notes 3, 10)	3,163	—
Risk Management	(Note 18)	29	2
Asset Retirement Obligation	(Note 15)	1,458	1,051
Future Income Taxes	(Note 9)	6,208	6,240
		26,270	17,640
Commitments and Contingencies	(Note 20)		
Shareholders' Equity			
Share capital	(Note 16)	4,479	4,587
Paid in surplus	(Note 16)	80	160
Retained earnings		13,082	11,344
Accumulated other comprehensive income		3,063	1,375
Total Shareholders' Equity		20,704	17,466
		$46,974	$35,106

See accompanying Notes to Consolidated Financial Statements

Approved by the Board

David P. O'Brien
Director

Barry W. Harrison
Director

Consolidated Statement of Cash Flows

For the years ended December 31 (US$ millions)		2007	2006	2005
Operating Activities				
Net earnings from continuing operations		$ 3,884	$ 5,051	$ 2,829
Depreciation, depletion and amortization		3,816	3,112	2,769
Future income taxes	(Note 9)	(617)	950	56
Cash tax on sale of assets	(Note 9)	—	49	578
Unrealized (gain) loss on risk management	(Note 18)	1,235	(2,060)	469
Unrealized foreign exchange (gain) loss		41	—	(126)
Accretion of asset retirement obligation	(Note 15)	64	50	37
(Gain) loss on divestitures	(Note 6)	(65)	(323)	—
Other		95	214	350
Cash flow from discontinued operations		—	118	464
Net change in other assets and liabilities		(16)	138	(281)
Net change in non-cash working capital from continuing operations	(Note 19)	(8)	3,343	497
Net change in non-cash working capital from discontinued operations		—	(2,669)	(212)
Cash From Operating Activities		8,429	7,973	7,430
Investing Activities				
Capital expenditures	(Note 4)	(8,737)	(6,600)	(6,925)
Proceeds from divestitures	(Note 6)	481	689	2,523
Cash tax on sale of assets	(Note 9)	—	(49)	(578)
Net change in investments and other		(5)	2	(109)
Net change in non-cash working capital from continuing operations	(Note 19)	86	19	330
Discontinued operations		—	2,557	239
Cash (Used in) Investing Activities		(8,175)	(3,382)	(4,520)
Financing Activities				
Net issuance (repayment) of revolving long-term debt		181	134	(538)
Issuance of long-term debt	(Note 14)	2,409	—	429
Repayment of long-term debt	(Note 14)	(257)	(73)	(1,104)
Issuance of common shares	(Note 16)	176	179	294
Purchase of common shares	(Note 16)	(2,025)	(4,219)	(2,114)
Dividends on common shares		(603)	(304)	(238)
Other		—	(11)	(125)
Cash (Used in) From Financing Activities		(119)	(4,294)	(3,396)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		16	—	(2)
Increase (Decrease) in Cash and Cash Equivalents		151	297	(488)
Cash and Cash Equivalents, Beginning of Year		402	105	593
Cash and Cash Equivalents, End of Year		$ 553	$ 402	$ 105
Supplemental Cash Flow Information	(Note 19)			

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

Prepared using Canadian Generally Accepted Accounting Principles
All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2007

1. Summary of Significant Accounting Policies

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana's functional currency is Canadian dollars; EnCana has adopted the U.S. dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana's continuing operations are in the business of exploration for, production and marketing of natural gas, crude oil and natural gas liquids ("NGLs"), refining operations and power generation operations.

A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 22.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana's exploration, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby EnCana's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) FOREIGN CURRENCY TRANSLATION

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included in Accumulated Other Comprehensive Income ("AOCI") as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) MEASUREMENT UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which, by their nature, are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance-based compensation arrangements are subject to management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

D) REVENUE RECOGNITION

Revenues associated with the sales of EnCana's natural gas, crude oil, NGLs and petroleum and chemical products are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) PRODUCTION AND MINERAL TAXES

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) TRANSPORTATION AND SELLING COSTS

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs, including diluent, are recognized when the product is delivered and the services provided.

G) EMPLOYEE BENEFIT PLANS

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement and post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is done on a straight-line basis over a period covering the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

H) INCOME TAXES

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

I) EARNINGS PER SHARE AMOUNTS

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options without tandem share appreciation rights attached were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

K) INVENTORIES

Product inventories, including petroleum and chemical products, are valued at the lower of average cost and net realizable value on a first-in, first-out basis.

L) PROPERTY, PLANT AND EQUIPMENT

Upstream

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and

ii. the costs of unproved properties that have been subject to a separate impairment test.

Downstream

The initial acquisition costs of refinery property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over their estimated service lives of approximately 25 years.

An impairment loss is recognized on refinery property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset.

Market Optimization

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic lives, which range from 20 to 35 years.

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Assets under construction are not subject to depreciation until put into use. Land is carried at cost.

M) CAPITALIZATION OF COSTS

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

N) AMORTIZATION OF OTHER ASSETS

Amortization of deferred items included in Investments and Other Assets is provided for where applicable, on a straight-line basis over the estimated useful lives of the assets.

O) GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

P) ASSET RETIREMENT OBLIGATION

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants, and refining facilities. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) STOCK-BASED COMPENSATION

EnCana records compensation expense in the Consolidated Financial Statements for stock options that do not have tandem share appreciation rights attached to them granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes-Merton option-pricing model. Compensation costs are recognized over the vesting period.

Obligations for payments, cash or common shares, under the Company's share appreciation rights, stock options with tandem share appreciation rights attached, deferred share units and performance share units plans are accrued as compensation expense over the vesting period. Fluctuations in the price of EnCana's common shares change the accrued compensation expense and are recognized when they occur.

R) FINANCIAL INSTRUMENTS

On January 1, 2007, the Company adopted the CICA Handbook Section 3855, *"Financial Instruments – Recognition and Measurement"* (See Note 2).

Financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the accounting standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held-for-trading" and are measured at fair value. Accounts receivable and accrued revenues and the partnership contribution receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the partnership contribution payable and long-term debt are designated as "other financial liabilities". EnCana capitalizes long-term debt transaction costs, premiums and discounts. These costs are capitalized within long-term debt and amortized using the effective interest method.

Derivative Financial Instruments

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) RECENT ACCOUNTING PRONOUNCEMENTS

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have an impact on the Company:

- As of January 1, 2008, EnCana will be required to adopt the CICA Handbook Section 3031, *"Inventories"*, which will replace the existing inventories standard. The new standard requires inventory to be valued on a first-in, first-out or weighted average basis, which is consistent with EnCana's current treatment. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862, *"Financial Instruments – Disclosures"* and Section 3863, *"Financial Instruments – Presentation"*, which will replace Section 3861, *"Financial Instruments – Disclosure and Presentation"*. The new disclosure standard will increase EnCana's disclosure regarding the risks associated with financial instruments and how those risks are managed.
- As of January 1, 2008, EnCana will be required to adopt CICA Handbook Section 1535, *"Capital Disclosures"*, which will require EnCana to disclose its objectives, policies and processes for managing capital.

- In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRSs"). In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRSs into Canadian GAAP"*, which assumes a convergence date of January 1, 2011. Following a progress review, the AcSB is expected to confirm this date by March 31, 2008. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

T) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2007.

2. Changes in Accounting Policies and Practices

On January 1, 2007, the Company adopted the CICA Handbook Section 1530, *"Comprehensive Income"*, Section 3251, *"Equity"*, Section 3855, *"Financial Instruments – Recognition and Measurement"*, and Section 3865, *"Hedges"*. As required by the new standards, prior periods have not been restated, except to reclassify the foreign currency translation adjustment balance as described under Comprehensive Income.

The adoption of these standards has had no material impact on the Company's net earnings or cash flows. The other effects of the implementation of the new standards are discussed below.

COMPREHENSIVE INCOME

The new standards introduce comprehensive income, which consists of net earnings and OCI. The Company's Consolidated Financial Statements now include a Statement of Comprehensive Income, which includes the components of comprehensive income. For EnCana, OCI is currently comprised of the changes in the foreign currency translation adjustment balance.

The cumulative changes in OCI are included in AOCI, which is presented as a new category within shareholders' equity in the Consolidated Balance Sheet. The accumulated foreign currency translation adjustment, formerly presented as a separate category within shareholders' equity, is now included in AOCI. The Company's Consolidated Financial Statements now include a Statement of Accumulated Other Comprehensive Income, which provides the continuity of the AOCI balance.

The adoption of comprehensive income has been made in accordance with the applicable transitional provisions. Accordingly, the December 31, 2007 period end accumulated foreign currency translation adjustment balance of $3,063 million is now included in AOCI (2006 – $1,375 million; 2005 – $1,262 million). In addition, the change in the accumulated foreign currency translation adjustment balance for the year ended December 31, 2007 of $1,688 million is now included in OCI in the Statement of Comprehensive Income (2006 – $113 million; 2005 – $226 million).

FINANCIAL INSTRUMENTS

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. EnCana's accounting policies for financial instruments are described in Note 1.

The adoption of the financial instruments standard has been made in accordance with its transitional provisions. Accordingly, at January 1, 2007, $52 million of other assets were reclassified to long-term debt to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt. The costs capitalized within long-term debt will be amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. The adoption of the effective interest method of amortization had no effect on opening retained earnings.

3. Joint Venture with ConocoPhillips

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consists of an upstream and a downstream entity. The upstream entity contribution included assets from EnCana, primarily the Foster Creek and Christina Lake properties, with a fair value of $7.5 billion and a note receivable contributed from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas respectively, for a fair value of $7.5 billion and EnCana contributed a note payable of $7.5 billion. Further information about these notes is included in Note 10.

In accordance with Canadian generally accepted accounting principles, these entities have been accounted for using the proportionate consolidation method with the results of operations shown in a separate business segment, Integrated Oil (See Note 4).

4. Segmented Information

The Company has defined its continuing operations into the following segments:

- Canada, United States and Other includes the Company's upstream exploration for, and development and production of natural gas, crude oil and natural gas liquids and other related activities. The majority of the Company's upstream operations are located in Canada and the United States. Offshore and international exploration is mainly focused on opportunities in Atlantic Canada, the Middle East and Europe.
- Integrated Oil is focused on two lines of business: the exploration for, and development and production of bitumen in Canada using in-situ recovery methods; and the refining of crude oil into petroleum and chemical products located in the United States. This segment represents EnCana's 50 percent interest in the joint venture with ConocoPhillips.
- Market Optimization is conducted by the Midstream & Marketing division. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Canada, United States and Integrated Oil segments. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- Corporate includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization markets substantially all of the Company's upstream production to third-party customers. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

In 2007, as a result of the joint venture with ConocoPhillips, EnCana redefined its business segments to those described above. All prior periods have been restated to conform with the current presentation.

Operations that have been discontinued are disclosed in Note 5.

Results of Continuing Operations

	Upstream								
	Canada			United States			Other		
For the years ended December 31	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$ 7,316**	$ 6,970	$ 6,783	**$ 4,074**	$ 3,121	$ 3,177	**$ 368**	$ 278	$ 258
Expenses									
Production and mineral taxes	**102**	116	104	**189**	233	349	**–**	–	–
Transportation and selling	**327**	330	300	**307**	248	182	**–**	–	–
Operating	**1,010**	866	727	**323**	283	212	**315**	235	246
Purchased product	**–**	–	–	**–**	–	–	**–**	–	–
Depreciation, depletion and amortization	**2,171**	1,989	1,815	**1,158**	848	682	**94**	31	75
Segment Income (Loss)	**$ 3,706**	$ 3,669	$ 3,837	**$ 2,097**	$ 1,509	$ 1,752	**$ (41)**	$ 12	$ (63)

	Total Upstream			Integrated Oil			Market Optimization		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$11,758**	$10,369	$10,218	**$ 7,983**	$ 973	$ 554	**$ 2,944**	$ 3,007	$ 4,267
Expenses									
Production and mineral taxes	**291**	349	453	**–**	–	–	**–**	–	–
Transportation and selling	**634**	578	482	**366**	476	350	**10**	16	13
Operating	**1,648**	1,384	1,185	**598**	221	166	**37**	62	85
Purchased product	**–**	–	–	**5,725**	–	–	**2,858**	2,862	4,159
Depreciation, depletion and amortization	**3,423**	2,868	2,572	**284**	157	116	**17**	12	8
Segment Income (Loss)	**$ 5,762**	$ 5,190	$ 5,526	**$ 1,010**	$ 119	$ (78)	**$ 22**	$ 55	$ 2

	Corporate			Consolidated		
	2007	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$(1,239)**	$ 2,050	$ (466)	**$21,446**	$16,399	$14,573
Expenses						
Production and mineral taxes	**–**	–	–	**291**	349	453
Transportation and selling	**–**	–	–	**1,010**	1,070	845
Operating	**(5)**	(12)	2	**2,278**	1,655	1,438
Purchased product	**–**	–	–	**8,583**	2,862	4,159
Depreciation, depletion and amortization	**92**	75	73	**3,816**	3,112	2,769
Segment Income (Loss)	**$(1,326)**	$ 1,987	$ (541)	**5,468**	7,351	4,909
Administrative				**384**	271	268
Interest, net				**428**	396	524
Accretion of asset retirement obligation				**64**	50	37
Foreign exchange (gain) loss, net				**(164)**	14	(24)
Stock-based compensation – options				**–**	–	15
(Gain) loss on divestitures				**(65)**	(323)	–
				647	408	820
Net Earnings Before Income Tax				**4,821**	6,943	4,089
Income tax expense				**937**	1,892	1,260
Net Earnings From Continuing Operations				**$ 3,884**	$ 5,051	$ 2,829

Geographic and Product Information (Continuing Operations)

	Produced Gas								
	Canada			United States			Total		
For the years ended December 31	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$ 5,671**	$ 5,440	$ 5,486	**$ 3,765**	$ 2,854	$ 2,932	**$ 9,436**	$ 8,294	$ 8,418
Expenses									
Production and mineral taxes	**70**	80	76	**167**	213	325	**237**	293	401
Transportation and selling	**285**	278	283	**307**	248	182	**592**	526	465
Operating	**744**	629	521	**323**	283	212	**1,067**	912	733
Operating Cash Flow	**$ 4,572**	$ 4,453	$ 4,606	**$ 2,968**	$ 2,110	$ 2,213	**$ 7,540**	$ 6,563	$ 6,819

	Oil and NGLs								
	Canada			United States			Total		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$ 1,645**	$ 1,530	$ 1,297	**$ 309**	$ 267	$ 245	**$ 1,954**	$ 1,797	$ 1,542
Expenses									
Production and mineral taxes	**32**	36	28	**22**	20	24	**54**	56	52
Transportation and selling	**42**	52	17	**—**	—	—	**42**	52	17
Operating	**266**	237	206	**—**	—	—	**266**	237	206
Operating Cash Flow	**$ 1,305**	$ 1,205	$ 1,046	**$ 287**	$ 247	$ 221	**$ 1,592**	$ 1,452	$ 1,267

	Integrated Oil								
	Oil			Downstream Refining			Other		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues, Net of Royalties	**$ 738**	$ 941	$ 529	**$ 7,315**	$ —	$ —	**$ (70)**	$ 32	$ 25
Expenses									
Transportation and selling	**366**	476	350	**—**	—	—	**—**	—	—
Operating	**159**	194	137	**428**	—	—	**11**	27	29
Purchased product	**—**	—	—	**5,813**	—	—	**(88)**	—	—
Operating Cash Flow	**$ 213**	$ 271	$ 42	**$ 1,074**	$ —	$ —	**$ 7**	$ 5	$ (4)

	Integrated Oil		
	Total		
	2007	2006	2005
Revenues, Net of Royalties	**$ 7,983**	$ 973	$ 554
Expenses			
Transportation and selling	**366**	476	350
Operating	**598**	221	166
Purchased product	**5,725**	—	—
Operating Cash Flow	**$ 1,294**	$ 276	$ 38

Capital Expenditures (Continuing Operations)

For the years ended December 31	2007	2006	2005
Capital			
Canada	$ 3,330	$ 3,352	$ 3,702
United States	1,919	2,061	1,982
Other	106	106	125
Integrated Oil	580	632	393
Market Optimization	6	44	197
Corporate	94	74	78
	6,035	6,269	6,477
Acquisition Capital			
Canada	75	11	30
United States	2,613	284	418
Other	—	15	—
Integrated Oil	14	21	—
	2,702	331	448
Total	$ 8,737	$ 6,600	$ 6,925

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. Pursuant to the agreement with Brown Kilgore, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangement with Brown Kilgore will be complete on May 18, 2008 and the assets will be transferred to EnCana at that time. EnCana has determined that the relationship with Brown Kilgore represents an interest in a Variable Interest Entity ("VIE") and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Kilgore from the date of acquisition.

ADDITIONS TO GOODWILL

There were no additions to goodwill during 2007 or 2006.

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
As at December 31	2007	2006	2007	2006
Canada	$ 17,631	$ 16,783	$ 21,429	$ 20,188
United States	11,879	8,494	12,948	9,509
Other	1,104	1,182	1,135	1,224
Integrated Oil	4,721	1,322	9,597	1,379
Market Optimization	171	154	478	468
Corporate	359	278	1,387	2,338
Total	$ 35,865	$ 28,213	$ 46,974	$ 35,106

Property, Plant and Equipment, Goodwill and Total Assets by Geographic Region

	Goodwill		Property, Plant and Equipment		Total Assets	
As at December 31	2007	2006	2007	2006	2007	2006
Canada	$ 2,420	$ 2,052	$ 20,143	$ 19,456	$ 28,774	$ 25,268
United States	473	473	15,585	8,494	17,963	9,481
Other Countries	—	—	137	263	237	357
Total	$ 2,893	$ 2,525	$ 35,865	$ 28,213	$ 46,974	$ 35,106

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third-party developer. Corporate Property, Plant and Equipment and Total Assets include EnCana's accrual to date of $147 million related to this office project as an asset under construction. A corresponding liability is included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project.

EXPORT SALES

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were $1,362 million (2006 – $1,814 million; 2005 – $1,784 million).

MAJOR CUSTOMERS

In connection with the marketing and sale of EnCana's own and purchased natural gas, crude oil and refined products for the year ended December 31, 2007, the Company had two customers (2006 – one; 2005 – one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to these customers, major international integrated energy companies with a high quality investment grade credit rating, were approximately $7,652 million (2006 – $1,951 million; 2005 – $2,056 million).

5. Discontinued Operations

As EnCana has focused its continuing operations on North American Upstream and Downstream operations, a number of divestitures have been made which are accounted for as discontinued operations.

MIDSTREAM

The $75 million gain on discontinuance in 2007 is the result of an expired clause included in the December 2005 sale of the Company's Midstream natural gas liquids processing operations. The clause provided potential market price support for the facilities and was accrued for in 2005.

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately $1.5 billion and an after-tax gain on sale of $829 million was recorded.

On December 13, 2005, EnCana completed the sale of its natural gas liquids processing operations for proceeds of $625 million (C$720 million) and recorded an after-tax gain on sale of $370 million.

ECUADOR

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of $1.4 billion before indemnifications. A loss of $279 million, including the impact of indemnifications, was recorded. Indemnifications are discussed further in this note.

Amounts recorded as depreciation, depletion and amortization in 2006 and 2005 represent provisions which were recorded against the net book value of the Ecuador operations to recognize Management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

UNITED KINGDOM

On December 1, 2004, EnCana completed the sale of its 100 percent interest in EnCana (U.K.) Limited, holder of its U.K. operations, for net cash consideration of approximately $2.1 billion. A gain on sale of approximately $1.4 billion was recorded.

CONSOLIDATED STATEMENT OF EARNINGS

The following tables present the effect of the discontinued operations in the Consolidated Statement of Earnings:

		Midstream		Ecuador		United Kingdom	
For the years ended December 31	**2007**	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties (1)	**$ –**	$ 482	$ 1,570	$ 200	$ 965	$ —	$ —
Expenses							
Production and mineral taxes	**–**	—	—	23	131	—	—
Transportation and selling	**–**	—	9	10	58	—	—
Operating	**–**	37	301	25	138	—	—
Purchased product	**–**	356	1,100	—	—	—	—
Depreciation, depletion and amortization	**–**	—	28	84	234	—	—
Administrative	**–**	—	30	—	—	—	—
Interest, net	**–**	—	(2)	(2)	(2)	—	—
Accretion of asset retirement obligation	**–**	—	—	—	1	—	—
Foreign exchange (gain) loss, net	**–**	4	(2)	1	(4)	(1)	(40)
(Gain) loss on discontinuance	**(75)**	(807)	(364)	279	—	—	—
	(75)	(410)	1,100	420	556	(1)	(40)
Net Earnings (Loss) Before Income Tax	**75**	892	470	(220)	409	1	40
Income tax expense (recovery)	**–**	17	39	59	278	(4)	5
Net Earnings (Loss) from Discontinued Operations	**$ 75**	$ 875	$ 431	$ (279)	$ 131	$ 5	$ 35

(1) Revenues, net of royalties in Ecuador for 2006 include realized losses of $1 million related to derivative financial instruments.

		Consolidated Total	
For the years ended December 31	**2007**	2006	2005
Revenues, Net of Royalties	**$ –**	$ 682	$ 2,535
Expenses			
Production and mineral taxes	**–**	23	131
Transportation and selling	**–**	10	67
Operating	**–**	62	439
Purchased product	**–**	356	1,100
Depreciation, depletion and amortization	**–**	84	262
Administrative	**–**	—	30
Interest, net	**–**	(2)	(4)
Accretion of asset retirement obligation	**–**	—	1
Foreign exchange (gain) loss, net	**–**	4	(46)
(Gain) loss on discontinuance	**(75)**	(528)	(364)
	(75)	9	1,616
Net Earnings (Loss) Before Income Tax	**75**	673	919
Income tax expense (recovery)	**–**	72	322
Net Earnings (Loss) From Discontinued Operations	**$ 75**	$ 601	$ 597
Net Earnings (Loss) From Discontinued Operations per Common Share			
Basic	**$ 0.10**	$ 0.73	$ 0.69
Diluted	**$ 0.10**	$ 0.72	$ 0.67

There were no assets and liabilities related to discontinued operations as at December 31, 2007.

COMMITMENTS AND CONTINGENCIES

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount calculated in accordance with the terms of the agreements, approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

6. Divestitures

For the years ended December 31	2007	2006	2005
Canada	$ 54	$ 59	$ 447
United States	10	19	2,074
Other	360	367	—
Market Optimization	—	244	—
Corporate	57	—	2
	$ 481	$ 689	$ 2,523

Proceeds received on the sale of assets and investments in 2007 were $481 million (2006 – $689 million; 2005 – $2,523 million) as described below:

CANADA AND UNITED STATES

In 2007, EnCana completed the divestiture of mature conventional oil and natural gas assets for proceeds of $64 million (2006 – $78 million; 2005 – $471 million).

In May 2005, EnCana completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $578 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

OTHER

In August 2007, the Company closed the sale of Australia assets for proceeds of $31 million resulting in a gain on sale of $30 million. After recording income tax of $5 million, EnCana recorded an after-tax gain of $25 million.

In May 2007, the Company completed the sale of its assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million, which were credited to property, plant and equipment.

In January 2007, the Company completed the sale of its interests in Chad, properties that were in the pre-production stage, for proceeds of $208 million which resulted in a gain on sale of $59 million.

In August 2006, EnCana completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $367 million which resulted in a gain on sale of $304 million. After recording income tax of $49 million, EnCana recorded an after-tax gain of $255 million.

MARKET OPTIMIZATION

In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately $244 million which resulted in a gain on sale of $17 million.

CORPORATE

In February 2007, the Company sold The Bow office project assets for proceeds of approximately $57 million, largely representing its investment at the date of sale. Refer to Note 4 for further discussion of The Bow office project assets.

7. Interest, Net

For the years ended December 31	2007	2006	2005
Interest Expense – Long-Term Debt	$ 460	$ 366	$ 417
Early Retirement of Long-Term Debt	—	—	121
Interest Expense – Other (1)	244	76	18
Interest Income (1)	(276)	(46)	(32)
	$ 428	$ 396	$ 524

(1) In 2007, Interest Expense – Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively. See Note 10.

During 2005, EnCana redeemed a number of unsecured notes with a principal of C$1,150 million. The $121 million before tax ($79 million after-tax) charge is due to the early retirement of these medium term notes.

EnCana has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions detailed below (See Note 14). The net effect of these transactions reduced interest costs in 2007 by $4 million (2006 – $7 million; 2005 – $16 million).

Swap Positions

As at December 31, 2007	Principal Amount	Indenture Interest	Net Swap To	Effective Rate
5.80% due June 2, 2008	US$71 million	C$ Fixed	US$ Fixed (1)	4.80%
C$225 million				
	C$125 million	C$ Fixed	C$ Floating	3 month Bankers' Acceptance less 5 basis points

(1) This instrument has been subject to multiple swap transactions.

8. Foreign Exchange (Gain) Loss, Net

For the years ended December 31	2007	2006	2005
Unrealized Foreign Exchange (Gain) Loss on:			
Translation of U.S. dollar debt issued from Canada	$ (683)	$ —	$ (113)
Translation of U.S. dollar partnership contribution receivable issued from Canada	617	—	—
Other Foreign Exchange (Gain) Loss	(98)	14	89
	$ (164)	$ 14	$ (24)

9. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31	2007	2006	2005
Current			
Canada	$ 900	$ 764	$ 493
United States	647	128	719
Other	7	50	(8)
Total Current Tax	1,554	942	1,204
Future	(316)	1,407	56
Future Tax Rate Reductions	(301)	(457)	—
Total Future Tax	(617)	950	56
	$ 937	$ 1,892	$ 1,260

Included in current tax for 2006 is $49 million related to the sale of assets in Brazil (2005 – $578 million related to the sale of the Gulf of Mexico assets).

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

For the years ended December 31	2007	2006	2005
Net Earnings Before Income Tax	$ 4,821	$ 6,943	$ 4,089
Canadian Statutory Rate	32.3%	34.7%	37.9%
Expected Income Tax	1,557	2,407	1,550
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	—	97	207
Canadian resource allowance	—	(16)	(202)
Statutory and other rate differences	76	(98)	(235)
Effect of tax rate changes	(301)	(457)	—
Effect of legislative changes	(179)	—	—
Non-taxable downstream partnership income	(70)	—	—
Non-taxable capital gains	(124)	(1)	(24)
Tax basis retained on divestitures	—	—	(68)
Large corporations tax	—	—	25
Other	(22)	(40)	7
	$ 937	$ 1,892	$ 1,260
Effective Tax Rate	19.4%	27.3%	30.8%

The net future income tax liability is comprised of:

As at December 31	2007	2006
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	$ 5,401	$ 4,695
Timing of partnership items	961	1,251
Other	—	305
Future Tax Assets		
Non-capital and net operating losses carried forward	(6)	(11)
Other	(148)	—
Net Future Income Tax Liability	$ 6,208	$ 6,240

The approximate amounts of tax pools available are as follows:

As at December 31	**2007**	2006
Canada	**$11,014**	$ 9,352
United States	**7,101**	3,409
	$18,115	$12,761

Included in the above tax pools are $23 million (2006 – $39 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2008 and 2027.

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a year end that is after that of EnCana Corporation.

10. Partnership Contribution Receivable/Payable

PARTNERSHIP CONTRIBUTION RECEIVABLE

On January 2, 2007, upon the creation of the Integrated Oil joint venture, ConocoPhillips entered into a subscription agreement for a 50 percent interest in the upstream entity in exchange for a promissory note of $7.5 billion. The note bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution receivable shown in the Consolidated Balance Sheet represents EnCana's 50 percent share of this promissory note, net of payments to date.

Mandatory Receipts	2008	2009	2010	2011	2012	Thereafter	**Total**
Partnership Contribution Receivable	$ 297	$ 313	$ 330	$ 347	$ 366	$ 1,791	**$ 3,444**

PARTNERSHIP CONTRIBUTION PAYABLE

On January 2, 2007, upon the creation of the Integrated Oil joint venture, EnCana issued a promissory note to the downstream entity in the amount of $7.5 billion in exchange for a 50 percent interest. The note bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution payable amounts shown in the Consolidated Balance Sheet represents EnCana's 50 percent share of this promissory note, net of payments to date.

Mandatory Payments	2008	2009	2010	2011	2012	Thereafter	**Total**
Partnership Contribution Payable	$ 288	$ 306	$ 325	$ 345	$ 366	$ 1,821	**$ 3,451**

11. Inventories

As at December 31	2007	2006
Product		
Canada	$ —	$ 1
United States	2	—
Integrated Oil	646	49
Market Optimization	180	126
	$ 828	$ 176

12. Property, Plant and Equipment, Net

As at December 31	2007			2006		
	Cost	Accumulated DD&A (1)	Net	Cost	Accumulated DD&A (1)	Net
Canada	$ 36,618	$(18,987)	$ 17,631	$ 30,852	$(14,069)	$ 16,783
United States	15,681	(3,802)	11,879	11,105	(2,611)	8,494
Other	1,466	(362)	1,104	1,450	(268)	1,182
Integrated Oil – Upstream	1,131	(116)	1,015	1,347	(25)	1,322
Integrated Oil – Downstream	3,855	(149)	3,706	—	—	—
Market Optimization	253	(82)	171	207	(53)	154
Corporate	817	(458)	359	616	(338)	278
	$ 59,821	$(23,956)	$ 35,865	$ 45,577	$(17,364)	$ 28,213

(1) Depreciation, depletion and amortization

Canada, United States, Other and Integrated Oil – Upstream property, plant and equipment include internal costs directly related to exploration, development and construction activities of $469 million (2006 – $365 million). Costs classified as administrative expenses have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. Integrated Oil – Downstream assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31	2007	2006	2005
Canada	$ 1,381	$ 1,449	$ 1,689
United States	1,852	956	870
Other Countries	137	263	248
Integrated Oil – Downstream	139	—	—
	$ 3,509	$ 2,668	$ 2,807

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. For the year ended December 31, 2007, the Company completed its impairment review of pre-production cost centres and determined that $68 million of costs should be charged to depreciation, depletion, and amortization in the Consolidated Statement of Earnings (2006 – $6 million; 2005 – $7 million).

Integrated Oil – Downstream expenditures capitalized during the construction phase are not subject to depreciation until put in use and total $139 million at December 31, 2007.

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2007 were:

	2008	2009	2010	2011	2012	Cumulative % Increase to 2019
Natural Gas ($/Mcf)						
Canada	6.55	6.71	6.67	6.60	6.58	—
United States	6.52	6.84	6.58	6.66	6.92	—
Crude Oil ($/barrel)						
Canada	46.90	45.40	45.05	43.98	42.98	(7)%
Natural Gas Liquids ($/barrel)						
Canada	65.81	66.26	67.37	67.67	67.76	—
United States	64.33	64.73	64.97	64.90	63.52	(2)%

13. Investments and Other Assets

As at December 31		2007	2006
Prepaid Capital		**$ 383**	$ 401
Deferred Asset – Integrated Oil		**159**	—
Deferred Pension Plan and Savings Plan		**50**	58
Deferred Financing Costs	(Notes 2, 14)	**—**	52
Equity Investment		**—**	6
Other		**15**	16
		$ 607	$ 533

14. Long-Term Debt

As at December 31	Note	2007	2006
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	B	**$ 1,506**	$ 1,456
Unsecured notes	C	**1,138**	793
		2,644	2,249
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	D	**495**	104
Unsecured notes	E	**6,421**	4,421
		6,916	4,525
Increase in Value of Debt Acquired	F	**66**	60
Debt Discounts and Financing Costs	G	**(83)**	—
Current Portion of Long-Term Debt	H	**(703)**	(257)
		$ 8,840	$ 6,577

A) OVERVIEW

Revolving Credit and Term Loan Borrowings

At December 31, 2007, EnCana Corporation had in place a revolving credit facility for C$4.5 billion or its equivalent amount in U.S. dollars ($4.6 billion). The facility, which matures in October 2012, is fully revolving for a period of five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders' rates for Canadian prime, U.S. base rate, Bankers' Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2007, one of EnCana's subsidiaries had in place a credit facility totaling $600 million. The facility, which matures in February 2012, is guaranteed by EnCana Corporation and is fully revolving for five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders' U.S. base rate or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers' Acceptances, Commercial Paper and LIBOR loans of $2,001 million (2006 – $1,560 million) maturing at various dates with a weighted average interest rate of 5.00 percent (2006 – 4.58 percent). These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2007 relating to revolving credit and term loan agreements were approximately $4 million (2006 – $5 million; 2005 – $4 million).

Unsecured Notes

Unsecured notes include medium term notes and senior notes that are issued from time to time under trust indentures.

EnCana has in place a debt shelf prospectus for Canadian unsecured medium term notes in the amount of C$2 billion. The shelf prospectus provides that debt securities in Canadian dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and maturity dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was renewed in 2007 and expires in June 2009. At December 31, 2007, C$2 billion ($2 billion) of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

EnCana has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the multijurisdictional disclosure system ("MJDS"). The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was renewed in 2006 and expires in October 2008. At December 31, 2007, the shelf prospectus was fully utilized.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the MJDS. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. The shelf prospectus was renewed in 2006 and expires in July 2008. At December 31, 2007, $2 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

B) CANADIAN REVOLVING CREDIT AND TERM LOAN BORROWINGS

	C$ Principal Amount	2007	2006
Bankers' Acceptances	$ 420	$ 425	$ 335
Commercial Paper	1,068	1,081	1,121
	$ 1,488	$ 1,506	$ 1,456

C) CANADIAN UNSECURED NOTES

	C$ Principal Amount	2007	2006
5.30% due December 3, 2007	$ —	$ —	$ 257
5.80% due June 2, 2008	125	126	107
3.60% due September 15, 2008	500	506	429
4.30% due March 12, 2012	500	506	—
	$ 1,125	$ 1,138	$ 793

D) U.S. REVOLVING CREDIT AND TERM LOAN BORROWINGS

	2007	2006
LIBOR	$ 20	$ —
Commercial Paper	475	104
	$ 495	$ 104

E) U.S. UNSECURED NOTES

	C$ Amount	2007	2006
5.80% due June 2, 2008	$ 70 (1)	$ 71	$ 71
4.60% due August 15, 2009		250	250
7.65% due September 15, 2010		200	200
6.30% due November 1, 2011		500	500
4.75% due October 15, 2013		500	500
5.80% due May 1, 2014		1,000	1,000
5.90% due December 1, 2017		700	—
8.125% due September 15, 2030		300	300
7.20% due November 1, 2031		350	350
7.375% due November 1, 2031		500	500
6.50% due August 15, 2034		750	750
6.625% due August 15, 2037		500	—
6.50% due February 1, 2038		800	—
		$ 6,421	$ 4,421

(1) The Company has entered into a cross-currency and interest rate swap transaction that effectively converts a portion of the Canadian dollar denominated note to U.S. dollars. The effective U.S. dollar principal is shown in the table.

The 5.80% note due May 1, 2014 was issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. This note is fully and unconditionally guaranteed by EnCana Corporation.

F) INCREASE IN VALUE OF DEBT ACQUIRED

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 21 years.

G) DEBT DISCOUNTS AND FINANCING COSTS

On January 1, 2007, upon adoption of the financial instruments standard, $52 million of long-term debt transaction costs, premiums and discounts were reclassified from other assets to long-term debt (See Note 2). The costs capitalized within long-term debt are being amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. During 2007, $25 million in transaction costs and discounts have been capitalized within long-term debt relating to the issuance of Canadian and U.S. unsecured notes.

H) CURRENT PORTION OF LONG-TERM DEBT

	C$ Principal Amount	2007	2006
5.30% medium term note due December 3, 2007	$ —	$ —	$ 257
5.80% medium term note due June 2, 2008	125	126	—
5.80% medium term note due June 2, 2008	—	71	—
3.60% medium term note due September 15, 2008	500	506	—
	$ 625	$ 703	$ 257

I) MANDATORY DEBT PAYMENTS

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2008	$ 625	$ 71	$ 703
2009	—	250	250
2010	—	200	200
2011	—	500	500
2012	1,988	495	2,507
Thereafter	—	5,400	5,400
Total	$ 2,613	$ 6,916	$ 9,560

The amount due in 2008 excludes Bankers' Acceptances, Commercial Paper and LIBOR loans, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

15. Asset Retirement Obligation

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas assets and refining facilities:

As at December 31	2007	2006
Asset Retirement Obligation, Beginning of Year	**$ 1,051**	$ 816
Liabilities Incurred	**89**	68
Liabilities Settled	**(100)**	(51)
Change in Estimated Future Cash Flows	**184**	172
Accretion Expense	**64**	50
Other	**170**	(4)
Asset Retirement Obligation, End of Year	**$ 1,458**	$ 1,051

The total undiscounted amount of estimated cash flows required to settle the obligation is $7,395 million (2006 – $5,334 million), which has been discounted using a weighted average credit-adjusted risk free rate of 5.85 percent (2006 – 5.66 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general Company resources at that time.

16. Share Capital

AUTHORIZED

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

ISSUED AND OUTSTANDING

As at December 31	2007		2006	
	Number (millions)	**Amount**	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**777.9**	**$ 4,587**	854.9	$ 5,131
Common Shares Issued under Option Plans	**8.3**	**176**	8.6	179
Stock-Based Compensation	**—**	**17**	—	11
Common Shares Purchased	**(36.0)**	**(301)**	(85.6)	(734)
Common Shares Outstanding, End of Year	**750.2**	**$ 4,479**	777.9	$ 4,587

NORMAL COURSE ISSUER BID

In 2007, the Company purchased 38.9 million Common Shares for total consideration of $2,025 million. Of the amount paid, $325 million was charged to Share capital and $1,700 million was charged to Retained earnings. Included in the Common Shares Purchased in 2007 are 2.9 million Common Shares distributed, valued at $24 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (See Note 17). For these Common Shares distributed, there was an $82 million adjustment to Retained earnings with a reduction to Paid in surplus of $106 million.

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under six consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 75.1 million Common Shares under the renewed Bid which commenced on November 13, 2007 and terminates on November 12, 2008. During January 2008, EnCana purchased approximately 3.0 million Common Shares under the Bid for total consideration of $191 million.

STOCK OPTIONS

EnCana has stock-based compensation plans that allow employees and directors to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right ("TSAR") attached to them (See Note 17).

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase EnCana Common Shares. Options granted on or after November 4, 1999 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. In addition, with respect to the February 13, 2007 grant, one third of the stock options granted were service based and two thirds were performance based. The performance based stock options only become exercisable subject to a vesting factor based on EnCana's performance relative to pre-determined key measures (See Note 17).

Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited ("CPL"), EnCana's former parent company, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase Common Shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

Directors' Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase Common Shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued and on October 25, 2005, the Company terminated the plan.

The following tables summarize the information about options to purchase Common Shares that do not have a TSAR attached to them:

As at December 31	**2007**		2006		2005	
	Stock Options (millions)	**Weighted Average Exercise Price(C$)**	Stock Options (millions)	Weighted Average Exercise Price (C$)	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	**11.8**	**23.17**	20.7	23.36	36.2	23.15
Exercised	**(8.3)**	**23.73**	(8.6)	23.60	(14.9)	22.90
Forfeited	**(0.1)**	**22.53**	(0.3)	23.80	(0.6)	21.71
Outstanding, End of Year	**3.4**	**21.82**	11.8	23.17	20.7	23.36
Exercisable, End of Year	**3.4**	**21.82**	11.8	23.17	16.8	23.21

As at December 31, 2007	Outstanding Options			Exercisable Options	
Range of Exercise Price (C$)	Number of Options Outstanding (millions)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Number of Options Outstanding (millions)	Weighted Average Exercise Price (C$)
11.00 to 21.99	**0.6**	**1.8**	**11.58**	**0.6**	**11.58**
22.00 to 23.99	**2.6**	**0.3**	**23.86**	**2.6**	**23.86**
24.00 to 25.99	**0.2**	**0.7**	**25.04**	**0.2**	**25.04**
	3.4	**0.6**	**21.82**	**3.4**	**21.82**

At December 31, 2007, there were 12.2 million Common Shares reserved for issuance under stock option plans (2006 – 20.7 million; 2005 – 29.3 million).

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair value method. Stock options granted subsequent to December 31, 2003 have an associated TSAR attached. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option-pricing model with weighted average assumptions for grants as follows:

For the year ended December 31	2003
Weighted Average Fair Value of Options Granted (C$)	$ 6.11
Risk-Free Interest Rate	3.87%
Expected Lives (years)	3.00
Expected Volatility	0.33
Annual Dividend per Share (C$/Common Share)	$ 0.20

At December 31, 2007 and 2006, the balance in Paid in surplus relates to stock-based compensation programs.

17. Compensation Plans

Where applicable, the amounts below have been restated to reflect the effect of the Common Share split approved in April 2005.

A) PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company sponsors defined benefit and defined contribution plans, providing pension and other post-employment benefits ("OPEB") to its employees.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recent filing is dated December 31, 2005, and the next required filing will be as at December 31, 2008.

Information about defined benefit pension and other post-employment benefit plans, based on actuarial estimations as at December 31, 2007 is as follows:

Accrued Benefit Obligation

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Accrued Benefit Obligation, Beginning of Year	**$ 308**	$ 294	**$ 45**	$ 39
Current service cost	**8**	9	**8**	7
Interest cost	**16**	15	**3**	2
Benefits paid	**(17)**	(18)	**(1)**	(1)
Actuarial (gain) loss	**(14)**	7	**(5)**	(2)
Contributions	**1**	1	**—**	—
Foreign exchange	**55**	—	**3**	—
Accrued Benefit Obligation, End of Year	**$ 357**	$ 308	**$ 53**	$ 45

Plan Assets

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Fair Value of Plan Assets, Beginning of Year	**$ 304**	$ 284	**$ —**	$ —
Actual return on plan assets	**5**	27	**—**	—
Employer contributions	**8**	10	**—**	—
Employees' contributions	**1**	1	**—**	—
Benefits paid	**(17)**	(18)	**—**	—
Foreign exchange	**54**	—	**—**	—
Fair Value of Plan Assets, End of Year	**$ 355**	$ 304	**$ —**	$ —

Accrued Benefit Asset (Liability)

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Funded Status – Plan Assets (less) than Benefit Obligation	**$ (2)**	$ (4)	**$ (53)**	$ (45)
Amounts Not Recognized:				
Unamortized net actuarial loss (gain)	**59**	54	**(3)**	2
Unamortized past service cost	**6**	7	**1**	1
Net transitional asset	**(3)**	(6)	**12**	13
Accrued Benefit Asset (Liability)	**$ 60**	$ 51	**$ (43)**	$ (29)

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Prepaid Benefit Cost	**$ 60**	$ 51	**$ —**	$ —
Accrued Benefit Cost	**—**	—	**(43)**	(29)
Net Amount Recognized	**$ 60**	$ 51	**$ (43)**	$ (29)

The Company's OPEB plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Discount Rate	**5.25%**	5.00%	**5.50%**	5.375%
Rate of Compensation Increase	**4.28%**	4.30%	**5.77%**	5.65%

The weighted average assumptions used to determine periodic expense are as follows:

	Pension Benefits		OPEB	
As at December 31	**2007**	2006	**2007**	2006
Discount Rate	**5.00%**	5.00%	**5.38%**	5.25%
Expected Long-Term Rate of Return on Plan Assets:				
Registered pension plans	**6.75%**	6.75%	**n/a**	n/a
Supplemental pension plans	**3.375%**	3.375%	**n/a**	n/a
Rate of Compensation Increase	**4.34%**	4.50%	**5.77%**	5.65%

The periodic expense for benefits is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2007**	2006	2005	**2007**	2006	2005
Current Service Cost	**$ 8**	$ 9	$ 6	**$ 8**	$ 7	$ 5
Interest Cost	**16**	15	14	**3**	2	2
Actual Return on Plan Assets	**(5)**	(27)	(29)	**—**	—	—
Actuarial (Gain) Loss on Accrued Benefit Obligation	**(13)**	6	29	**—**	—	—
Difference Between Actual and:						
Expected return on plan assets	**(14)**	11	15	**—**	—	—
Recognized actuarial gain (loss)	**17**	—	(24)	**—**	—	—
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	2	**—**	—	—
Amortization of Transitional Obligation	**(3)**	(3)	(3)	**1**	2	1
Defined Benefit Plans Expense	**$ 8**	$ 13	$ 10	**$ 12**	$ 11	$ 8
Defined Contribution Plans Expense	**$ 34**	$ 28	$ 22	**$ —**	$ —	$ —
Net Benefit Plan Expense	**$ 42**	$ 41	$ 32	**$ 12**	$ 11	$ 8

The average remaining service period of the active employees covered by the defined benefit pension plan is six years. The average remaining service period of the active employees covered by the OPEB plan is 12 years.

Assumed health care cost trend rates are as follows:

As at December 31	**2007**	2006
Health Care Cost Trend Rate for Next Year	**10.50%**	11.00%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2016**	2015

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on Total of Service and Interest Cost	$ 1	$ (1)
Effect on Post-Retirement Benefit Obligation	$ 5	$ (4)

The Company's pension plan asset allocations are as follows:

Asset Category	Target Allocation %		% of Plan Assets at December 31		Expected Long-Term Rate of Return
	Normal	Range	**2007**	2006	
Domestic Equity	35	25-45	**39**	39	
Foreign Equity	30	20-40	**27**	30	
Bonds	30	20-40	**27**	25	
Real Estate and Other	5	0-20	**7**	6	
Total	100		**100**	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company's contributions to the pension plans are subject to the results of the actuarial valuation and direction by the Pension Committee. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2007 (2006 – $1 million; 2005 – $1 million).

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2008	$ 18	$ 2
2009	19	2
2010	19	2
2011	20	3
2012	21	3
2013 – 2017	121	22
Total	$ 218	$ 34

B) TANDEM SHARE APPRECIATION RIGHTS

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 16 have an associated Tandem Share Appreciation Right ("TSAR") attached to them whereby the option holder has the right to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSARs vest and expire under the same terms and conditions as the underlying option.

The following tables summarize the information about the TSARs:

As at December 31	2007		2006	
	Outstanding TSARs	Weighted Average Exercise Price	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**17,276,191**	**44.99**	8,403,967	38.41
Granted	**4,814,338**	**57.70**	11,180,800	49.01
Exercised – SARs	**(2,020,357)**	**41.20**	(700,418)	34.54
Exercised – Options	**(12,235)**	**35.04**	(32,948)	34.46
Forfeited	**(1,203,796)**	**50.02**	(1,575,210)	43.21
Outstanding, End of Year	**18,854,141**	**50.49**	17,276,191	44.99
Exercisable, End of Year	**5,267,550**	**43.18**	1,971,467	38.31

As at December 31, 2007	Outstanding TSARs			Exercisable Options with TSARs Attached	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
20.00 to 29.99	**346,843**	**1.35**	**27.54**	**346,843**	**27.54**
30.00 to 39.99	**4,254,009**	**2.12**	**38.20**	**2,266,281**	**38.16**
40.00 to 49.99	**8,278,327**	**3.10**	**48.15**	**2,187,192**	**48.08**
50.00 to 59.99	**4,961,922**	**4.03**	**56.02**	**406,584**	**55.26**
60.00 to 79.99	**1,013,040**	**4.39**	**64.32**	**60,650**	**63.00**
	18,854,141	**3.40**	**50.49**	**5,267,550**	**43.18**

During the year, the Company recorded compensation costs of $225 million related to the outstanding TSARs (2006 – $52 million; 2005 – $60 million).

C) PERFORMANCE TANDEM SHARE APPRECIATION RIGHTS

In 2007, under the terms of the existing Employee Stock Option Plan, EnCana granted Performance Tandem Share Appreciation Rights ("Performance TSARs") under which the employee has the right to receive a cash payment equal to the excess of the market price of EnCana Common Shares at the time of exercise over the grant price. Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited.

The following table summarizes the information about the Performance TSARs:

As at December 31	2007	
	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	–	–
Granted	7,275,575	56.09
Forfeited	(344,650)	56.09
Outstanding, End of Year	6,930,925	56.09
Exercisable, End of Year	–	–

As at December 31, 2007	Outstanding TSARs			Exercisable Options with TSARs Attached	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
50.00 to 59.99	6,930,925	4.12	56.09	–	–

During the year, EnCana recorded compensation costs of $21 million related to the outstanding Performance TSARs (2006 – nil).

D) DEFERRED SHARE UNITS

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. DSUs granted to Directors vest immediately. DSUs expire on December 15th of the year following the employee's retirement or death.

As at December 31	2007		2006	
	Outstanding DSUs	Average Share Price	Outstanding DSUs	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	866,577	29.56	836,561	26.81
Granted, Directors	79,168	57.02	70,000	56.71
Units, in Lieu of Dividends	9,314	62.80	12,578	54.69
Exercised	(365,885)	29.56	(52,562)	27.92
Outstanding, End of Year	589,174	33.78	866,577	29.56
Exercisable, End of Year	589,174	33.78	866,577	29.56

During the year, the Company recorded compensation costs of $14 million related to the outstanding DSUs (2006 – $5 million; 2005 – $16 million).

E) PERFORMANCE SHARE UNITS

EnCana has in place a program whereby employees may be granted Performance Share Units ("PSUs") which entitle the employee to receive, upon vesting, either a Common Share of EnCana or a cash payment equal to the value of one Common Share of EnCana depending upon the terms of the PSU granted. PSUs vest at the end of a three year period. Their ultimate value will depend upon EnCana's performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed comparison group of North American oil and gas companies. If EnCana's performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana's performance is at or above the specified level compared to the comparison group, the value of the PSUs shall be determined by EnCana's relative ranking, with payments ranging from one half to two times the PSUs granted for the 2004 and 2005 grant. These will be paid in Common Shares.

PSUs granted in 2003 were paid out in cash at 75 percent of the number granted. PSUs granted in 2004 were paid out in Common Shares at 100 percent of the number granted.

The following table summarizes the information about the PSUs:

As at December 31	2007		2006	
	Outstanding PSUs	Average Share Price	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**4,766,329**	**31.24**	5,443,997	30.65
Granted	**23,097**	**62.84**	41,459	54.82
Paid out	**(2,937,491)**	**26.98**	(239,794)	23.26
Forfeited	**(166,899)**	**34.38**	(479,333)	31.35
Outstanding, End of Year	**1,685,036**	**38.79**	4,766,329	31.24

During the year, the Company recorded compensation costs of $43 million related to the outstanding PSUs (2006 – $27 million; 2005 – $91 million).

At December 31, 2007, EnCana had approximately 2.6 million Common Shares held in trust for issuance upon vesting of the PSUs (2006 – 5.5 million).

F) SHARE APPRECIATION RIGHTS

EnCana has in place a program whereby certain employees are granted Share Appreciation Rights ("SARs") which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right. SARs granted generally expire after five years with the exception of a limited number that expire after seven years.

The Company has not granted any SARs after 2002. There are no outstanding SARs at December 31, 2007.

The following tables summarize the information about the SARs:

As at December 31	2007		2006	
	Outstanding SARs	**Weighted Average Exercise Price**	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**–**	**–**	246,739	23.13
Exercised	**–**	**–**	(246,739)	23.13
Forfeited	**–**	**–**	–	–
Outstanding, End of Year	**–**	**–**	–	–
Exercisable, End of Year	**–**	**–**	–	–
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**2,088**	**14.21**	319,511	14.33
Exercised	**(2,088)**	**14.21**	(317,423)	14.33
Outstanding, End of Year	**–**	**–**	2,088	14.21
Exercisable, End of Year	**–**	**–**	2,088	14.21

During the year, the Company has not recorded any compensation costs related to the outstanding SARs (2006 – reduction of compensation costs of $1 million; 2005 – compensation costs of $17 million).

18. Financial Instruments and Risk Management

As a means of managing commodity price volatility, EnCana has entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

The following tables summarize the realized and unrealized gains and losses on risk management activities:

	Realized Gain (Loss)		
For the years ended December 31	**2007**	2006	2005
Revenues, Net of Royalties	**$ 1,601**	$ 393	$ (684)
Operating Expenses and Other	**3**	5	31
Gain (Loss) on Risk Management – Continuing Operations	**1,604**	398	(653)
Gain (Loss) on Risk Management – Discontinued Operations	**–**	12	(155)
	$ 1,604	$ 410	$ (808)

	Unrealized Gain (Loss)		
For the years ended December 31	**2007**	2006	2005
Revenues, Net of Royalties	**$ (1,239)**	$ 2,050	$ (466)
Operating Expenses and Other	**4**	10	(3)
Gain (Loss) on Risk Management – Continuing Operations	**(1,235)**	2,060	(469)
Gain (Loss) on Risk Management – Discontinued Operations	**–**	20	50
	$ (1,235)	$ 2,080	$ (419)

FAIR VALUE OF OUTSTANDING RISK MANAGEMENT POSITIONS

The following table presents a reconciliation of the change in the unrealized amounts during 2007:

	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ 1,416	
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2007	353	$ 353
Fair Value of Contracts in Place at Transition that Expired During 2007	—	16
Foreign Exchange Gains on Canadian Dollar Contracts	2	—
Fair Value of Contracts Realized During 2007	(1,604)	(1,604)
Fair Value of Contracts, End of Year	$ 167	$ (1,235)

At December 31, 2007, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

As at December 31	2007	2006
Risk Management		
Current asset	$ 385	$ 1,403
Long-term asset	18	133
Current liability	207	14
Long-term liability	29	2
Net Risk Management Asset	$ 167	$ 1,520

Unrealized Fair Value Positions

A summary of all unrealized estimated fair value financial positions is as follows:

As at December 31	Note	2007	2006
Commodity Price Risk	A		
Natural gas		$ 346	$ 1,431
Crude oil		(199)	74
Power		19	13
Interest Rate Risk	B	2	4
Credit Derivatives	C	(1)	(2)
Total Fair Value		$ 167	$ 1,520

A) COMMODITY PRICE RISK

Natural Gas

At December 31, 2007 the Company's natural gas risk management activities from financial contracts had an unrealized gain and a fair market value position of $346 million. Details of the contracts are as follows:

	Notional Volumes (MMcf/d)	Term	Average Price	Fair Market Value
Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,583	2008	8.21 US$/Mcf	$ 303
Basis Contracts				
Canada	191	2008	(0.78) US$/Mcf	1
United States	1,049	2008	(1.02) US$/Mcf	65
Canada and United States (1)		2009-2011	US$/Mcf	(23)
Total Fair Value Positions				$ 346

(1) EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

Crude Oil

As at December 31, 2007, the Company's crude oil risk management activities from financial contracts had an unrealized loss and a fair market value position of $(199) million. Details of the contracts are as follows:

	Notional Volumes (bbls/d)	Term	Average Price	Fair Market Value
Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	23,000	2008	70.13 US$/bbl	$ (188)
				(188)
Other Financial Positions (1)				(11)
Total Fair Value Positions				$ (199)

(1) Other financial positions are part of the daily ongoing operations of the Company's proprietary production management.

Power

The Company has in place two Canadian dollar denominated derivative contracts, commencing January 1, 2007 for a period of 11 years, to manage its electricity consumption costs. At December 31, 2007, these contracts had an unrealized gain and a fair market value position of $19 million.

B) INTEREST RATE RISK

The Company has entered into various derivative contracts to manage the Company's interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrealized gains on the outstanding financial instruments were as follows:

	Unrealized Gain	
As at December 31	**2007**	2006
5.80% medium term note due June 2, 2008	**$ 2**	$ 4

At December 31, 2007, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $14 million (2006 – $11 million; 2005 – $10 million).

C) CREDIT RISK

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board of Directors has approved a credit policy governing the Company's credit portfolio and procedures are in place to ensure adherence to this policy.

With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings and net settlements where appropriate. At December 31, 2007, EnCana had one counterparty whose net settlement position individually accounts for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

D) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of cash and cash equivalents, accounts receivable and accounts payable approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is included in Note 10.

As at December 31	2007		2006	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets (1)				
Held-for-Trading:				
Cash and cash equivalents	**$ 553**	**$ 553**	$ 402	$ 402
Loans and Receivables:				
Accounts receivable and accrued revenues	**2,381**	**2,381**	1,721	1,721
Partnership Contribution Receivable, including current portion	**3,444**	**3,444**	—	—
Financial Liabilities (1)				
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**$ 3,982**	**$ 3,982**	$ 2,494	$ 2,494
Long-Term Debt, including current portion	**9,543**	**9,763**	6,834	6,965
Partnership Contribution Payable, including current portion	**3,451**	**3,451**	—	—

(1) Risk management assets and liabilities, which are classified as Held-for-Trading, are previously disclosed in this note.

19. Supplementary Information

A) PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

For the years ended December 31	2007	2006	2005
Weighted Average Common Shares Outstanding – Basic	**756.8**	819.9	868.3
Effect of Stock Options and Other Dilutive Securities	**7.8**	16.6	20.9
Weighted Average Common Shares Outstanding – Diluted	**764.6**	836.5	889.2

Information related to Common Shares and stock options has been restated to reflect the effect of the Common Share split approved in April 2005.

B) NET CHANGE IN NON-CASH WORKING CAPITAL FROM CONTINUING OPERATIONS

For the years ended December 31	2007	2006	2005
Operating Activities			
Accounts receivable and accrued revenues	**$ 33**	$ 3,128	$ (146)
Inventories	**42**	(75)	(34)
Accounts payable and accrued liabilities	**(78)**	(260)	654
Income tax payable	**(5)**	550	23
	$ (8)	$ 3,343	$ 497
Investing Activities			
Accounts payable and accrued liabilities	**$ 86**	$ 19	$ 330

C) SUPPLEMENTARY CASH FLOW INFORMATION – CONTINUING OPERATIONS

For the years ended December 31	2007	2006	2005
Interest Paid	**$ 422**	$ 341	$ 522
Income Taxes Paid	**$ 1,423**	$ 450	$ 1,096

20. Commitments and Contingencies

COMMITMENTS

As at December 31, 2007	2008	2009	2010	2011	2012	Thereafter	Total
Pipeline Transportation	$ 527	$ 479	$ 454	$ 483	$ 419	$ 2,222	**$ 4,584**
Purchases of Goods and Services	404	240	147	144	108	621	**1,664**
Product Purchases	24	24	24	23	—	98	**193**
Operating Leases (1)	70	74	78	210	209	3,402	**4,043**
Capital Commitments	54	10	3	130	3	39	**239**
Other Long-Term Commitments	18	10	6	3	—	1	**38**
Total	$ 1,097	$ 837	$ 712	$ 993	$ 739	$ 6,383	**$ 10,761**
Product Sales	$ 51	$ 47	$ 49	$ 51	$ 55	$ 244	**$ 497**

(1) Operating leases consist of building leases, including The Bow (See Note 4).

In addition to the above, the Company has made commitments related to its risk management program (See Note 18).

CONTINGENCIES

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (“WD”), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court for payment of $20.5 million and $2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission (“CFTC”), for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery (“Gallo”). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against the outstanding claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company’s financial position, or whether there will be other proceedings arising out of these allegations.

Asset Retirement

EnCana is responsible for the retirement of long-lived assets related to its oil and gas properties, refining facilities and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $1,458 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that EnCana operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

21. Subsequent Events

On January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

22. United States Accounting Principles and Reporting

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are described in this note.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31	Note	**2007**	2006	2005
Net Earnings – Canadian GAAP		**$ 3,959**	$ 5,652	$ 3,426
Less:				
Net Earnings From Discontinued Operations – Canadian GAAP		**75**	601	597
Net Earnings From Continuing Operations – Canadian GAAP		**3,884**	5,051	2,829
Increase (Decrease) in Net Earnings From Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	A	**(15)**	179	(217)
Operating	A, D ii)	**3**	(15)	1
Depreciation, depletion and amortization	B, D ii)	**86**	95	55
Administrative	D ii)	**1**	(8)	—
Interest, net	A	**(2)**	(15)	(16)
Stock-based compensation – options	C	**(5)**	—	(12)
Income tax expense	E	**(204)**	(80)	59
Net Earnings From Continuing Operations – U.S. GAAP		**3,748**	5,207	2,699
Net Earnings From Discontinued Operations – U.S. GAAP		**75**	644	553
Net Earnings Before Change in Accounting Policy – U.S. GAAP		**3,823**	5,851	3,252
Cumulative Effect of Change in Accounting Policy, net of tax	D ii)	**—**	(15)	—
Net Earnings – U.S. GAAP		**$ 3,823**	$ 5,836	$ 3,252
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		**$ 5.05**	$ 7.14	$ 3.75
Diluted		**$ 5.00**	$ 6.99	$ 3.66
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		**$ 5.05**	$ 7.12	$ 3.75
Diluted		**$ 5.00**	$ 6.98	$ 3.66

CONSOLIDATED STATEMENT OF EARNINGS – U.S. GAAP

For the years ended December 31	Note	2007	2006	2005
Revenues, Net of Royalties	A	$21,431	$16,578	$14,356
Expenses				
Production and mineral taxes		291	349	453
Transportation and selling		1,010	1,070	845
Operating	A, D ii)	2,275	1,670	1,437
Purchased product		8,583	2,862	4,159
Depreciation, depletion and amortization	B, D ii)	3,730	3,017	2,714
Administrative	D ii)	383	279	268
Interest, net	A	430	411	540
Accretion of asset retirement obligation		64	50	37
Foreign exchange (gain) loss, net		(164)	14	(24)
Stock-based compensation – options	C	5	—	27
(Gain) on divestitures		(65)	(323)	—
Net Earnings Before Income Tax		4,889	7,179	3,900
Income tax expense	E	1,141	1,972	1,201
Net Earnings From Continuing Operations – U.S. GAAP		3,748	5,207	2,699
Net Earnings From Discontinued Operations – U.S. GAAP		75	644	553
Net Earnings Before Change in Accounting Policy – U.S. GAAP		3,823	5,851	3,252
Cumulative Effect of Change in Accounting Policy, net of tax	D ii)	—	(15)	—
Net Earnings – U.S. GAAP		$ 3,823	$ 5,836	$ 3,252
Net Earnings From Continuing Operations per Common Share – U.S. GAAP				
Basic		$ 4.95	$ 6.35	$ 3.11
Diluted		$ 4.90	$ 6.22	$ 3.04
Net Earnings From Discontinued Operations per Common Share – U.S. GAAP				
Basic		$ 0.10	$ 0.79	$ 0.64
Diluted		$ 0.10	$ 0.77	$ 0.62
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		$ 5.05	$ 7.14	$ 3.75
Diluted		$ 5.00	$ 6.99	$ 3.66
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		$ 5.05	$ 7.12	$ 3.75
Diluted		$ 5.00	$ 6.98	$ 3.66

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2007	2006	2005
Net Earnings – U.S. GAAP		$ 3,823	$ 5,836	$ 3,252
Change in Fair Value of Financial Instruments	A, F	—	4	—
Foreign Currency Translation Adjustment	B, F, D ii)	1,707	(224)	573
Compensation Plans	F	1	—	—
Comprehensive Income		$ 5,531	$ 5,616	$ 3,825

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2007	2006	2005
Balance, Beginning of Year		$ 1,330	$ 1,598	$ 1,025
Change in Fair Value of Financial Instruments	A, F	—	4	—
Foreign Currency Translation Adjustment	B, F	1,707	(224)	573
Compensation Plans	D i), F	1	(48)	—
Balance, End of Year		$ 3,038	$ 1,330	$ 1,598

CONSOLIDATED STATEMENT OF RETAINED EARNINGS – U.S. GAAP

For the years ended December 31	2007	2006	2005
Retained Earnings, Beginning of Year	$ 11,374	$ 9,327	$ 7,955
Net Earnings	3,823	5,836	3,252
Dividends on Common Shares	(603)	(304)	(238)
Charges for Normal Course Issuer Bid	(1,618)	(3,485)	(1,642)
Retained Earnings, End of Year	$ 12,976	$ 11,374	$ 9,327

CONDENSED CONSOLIDATED BALANCE SHEET

As at December 31		2007		2006	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current Assets	D i)	$ 4,444	$ 4,446	$ 3,702	$ 3,703
Property, Plant and Equipment (includes unproved properties of $3,509 and $2,668 as of December 31, 2007 and 2006, respectively)	B, D ii)	59,821	59,729	45,577	45,496
Accumulated Depreciation, Depletion and Amortization		(23,956)	(23,669)	(17,364)	(17,197)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		35,865	36,060	28,213	28,299
Investments and Other Assets	D i)	607	557	533	488
Partnership Contribution Receivable		3,147	3,147	—	—
Risk Management		18	18	133	133
Goodwill		2,893	2,893	2,525	2,525
		$ 46,974	$ 47,121	$35,106	$35,148
Liabilities and Shareholders' Equity					
Current Liabilities	A, D i), ii), E	$ 6,330	$ 6,574	$ 3,691	$ 3,742
Long-Term Debt		8,840	8,840	6,577	6,577
Other Liabilities	A, D i) ii)	242	277	79	106
Partnership Contribution Payable		3,163	3,163	—	—
Risk Management		29	29	2	2
Asset Retirement Obligation		1,458	1,458	1,051	1,051
Future Income Taxes	E	6,208	6,172	6,240	6,189
		26,270	26,513	17,640	17,667
Share Capital	C				
Common Shares, no par value Outstanding: 2007 – 750.2 million shares 2006 – 777.9 million shares		4,479	4,514	4,587	4,617
Paid in Surplus		80	80	160	160
Retained Earnings		13,082	12,976	11,344	11,374
Accumulated Other Comprehensive Income	F	3,063	3,038	1,375	1,330
		20,704	20,608	17,466	17,481
		$ 46,974	$ 47,121	$35,106	$35,148

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS – U.S. GAAP

For the years ended December 31	2007	2006	2005
Operating Activities			
Net earnings from continuing operations	**$ 3,748**	$ 5,207	$ 2,699
Depreciation, depletion and amortization	**3,730**	3,017	2,714
Future income taxes	**(592)**	1,030	(4)
Unrealized (gain) loss on risk management	**1,251**	(2,229)	668
Unrealized foreign exchange (gain) loss	**41**	—	(126)
Accretion of asset retirement obligation	**64**	50	37
(Gain) on divestitures	**(65)**	(323)	—
Other	**97**	242	250
Cash flow from discontinued operations	**—**	118	464
Net change in other assets and liabilities	**(16)**	138	(281)
Net change in non-cash working capital from continuing operations	**(8)**	3,343	497
Net change in non-cash working capital from discontinued operations	**—**	(2,669)	(187)
Cash From Operating Activities	**$ 8,250**	$ 7,924	$ 6,731
Cash (Used in) Investing Activities	**$ (8,175)**	$ (3,333)	$ (3,942)
Cash (Used in) From Financing Activities	**$ (119)**	$ (4,294)	$ (3,275)

NOTES:

A) Derivative Instruments and Hedging

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 *"Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments"* which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2007, under Canadian GAAP, the remaining transition amount has been fully recognized into net earnings resulting in a $15 million decrease to revenue and $1 million increase to interest.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under SFAS 133.

Unrealized gain (loss) on derivatives relate to:

For the years ended December 31	2007	2006	2005
Commodity Prices (Revenues, net of royalties)	**$ (1,249)**	$ 2,327	$ (703)
Interest and Currency Swaps (Interest, net)	**(2)**	(11)	(9)
Total Unrealized Gain (Loss)	**$ (1,251)**	$ 2,316	$ (712)
Amounts Allocated to Continuing Operations	**$ (1,251)**	$ 2,229	$ (668)
Amounts Allocated to Discontinued Operations	—	87	(44)
	$ (1,251)	$ 2,316	$ (712)

As at December 31, 2007, it is estimated that over the following 12 months, $3.0 million ($2.0 million, net of tax) of the remaining SFAS 133 transition amount, will be reclassified into net earnings from other comprehensive income.

B) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP and U.S. GAAP differ in the following respects. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Depletion charges under U.S. GAAP are calculated by reference to proved reserves estimated using constant prices. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are calculated by reference to proved reserves estimated using estimated future prices and costs.
The U.S. GAAP adjustment results in an impact to depreciation, depletion and amortization charges and foreign currency translation adjustment of $85.4 million decrease and $2.9 million increase respectively (2006 – $97 million decrease and $1.2 million decrease; 2005 – $54.8 million decrease and $1 million increase).

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

C) Stock-Based Compensation – CPL Reorganization

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financial statements, which would be the same adjustment under U.S. GAAP, see Note 16.

Under Financial Accounting Standards Board ("FASB") Interpretation ("FIN") No. 44, *"Accounting for Certain Transactions Involving Stock Compensation"*, compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of Canadian Pacific Limited ("CPL"), an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 16. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) Compensation Plans

i) Pensions and Other Post-Employment Benefits

For the year ended December 31, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)"*. SFAS 158 requires EnCana to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through other comprehensive income. Canadian GAAP currently does not require the Company to recognize the funded status of these plans on its balance sheet.

ii) Tandem Share Appreciation Rights and Deferred Share Units

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, the Company adopted SFAS 123(R), *"Share-Based Payment"* for the year ended December 31, 2006 using the modified-prospective approach. Under SFAS 123(R), the intrinsic-method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights and deferred share units, are now required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. As a result:

- Net capital assets are lower by $8.4 million (2006 – $22.8 million higher)
- Current liabilities are lower by $10.8 million (2006 – $45.2 million higher)
- Other liabilities are lower by $2.8 million (2006 – $0.4 million higher)
- Other comprehensive income is higher by $0.5 million (2006 – $1.1 million higher)
- Operating expenses are lower by $3.3 million (2006 – $13.9 million higher)
- Administrative expenses are $0.5 million lower (2006 – $7.7 million higher)
- Depreciation, depletion and amortization expenses are $0.9 million lower (2006 – $2.3 million higher)

As the Company adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated, as required by the standard.

SFAS 123(R), under the modified prospective approach, requires the cumulative impact of a change in an accounting policy to be presented in the current year Consolidated Statement of Earnings. The cumulative effect, net of tax, of initially adopting SFAS 123(R) January 1, 2006 was a loss of $15 million.

E) Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate current and future income taxes, whereas Canadian GAAP uses substantively enacted tax rates. In 2007, a Canadian tax legislative change was substantively enacted for Canadian GAAP; however, this tax legislative change was not considered enacted for U.S. GAAP by December 31, 2007. The result is an increase to income tax expense of $179 million (2006 – nil, 2005 – nil) for U.S. GAAP.

The remaining differences resulted from the future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31	**2007**	2006	2005
Net Earnings Before Income Tax – U.S. GAAP	**$ 4,889**	$ 7,179	$ 3,900
Canadian Statutory Rate	**32.3%**	34.7%	37.9%
Expected Income Tax	**1,579**	2,491	1,478
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	**—**	97	207
Canadian resource allowance	**—**	(16)	(202)
Statutory and other rate differences	**76**	(98)	(235)
Effect of tax rate changes	**(301)**	(457)	—
Non-taxable downstream partnership income	**(70)**	—	—
Non-taxable capital gains	**(124)**	(1)	(24)
Tax basis retained on divestitures	**—**	—	(68)
Large corporations tax	**—**	—	25
Other	**(19)**	(44)	20
Income Tax – U.S. GAAP	**$ 1,141**	$ 1,972	$ 1,201
Effective Tax Rate	**23.3%**	27.5%	30.7%

The net future income tax liability is comprised of:

As at December 31	2007	2006
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 5,340**	$ 4,632
Timing of partnership items	**961**	1,251
Other	**—**	317
Future Tax Assets		
Non-capital and net operating losses carried forward	**(6)**	(11)
Other	**(123)**	—
Net Future Income Tax Liability	**$ 6,172**	$ 6,189

F) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of SFAS 133. At December 31, 2007, accumulated other comprehensive income related to these items was a loss of $2 million, net of tax.

At December 31, 2006, accumulated other comprehensive income related to the adoption of SFAS 158 was a loss of $48 million, net of tax. At December 31, 2007, other comprehensive income related to SFAS 158, as noted in D i) was a gain of $1.2 million, net of tax.

The foreign currency translation adjustment includes the effect of the accumulated U.S. GAAP differences.

G) Joint Venture with ConocoPhillips

Under Canadian GAAP, the Integrated Oil segment is proportionately consolidated. This segment represents the joint venture with ConocoPhillips. Under U.S. GAAP, the Downstream Refining operations included in this segment are to be equity accounted for. Equity accounting for the Downstream Refining operations would have no impact on EnCana's net earnings or retained earnings. As required, the following disclosures are provided for the Downstream Refining operations of the joint venture.

Income Statement

For the year ended December 31	2007
Operating Cash Flow (See Note 4)	**$ 1,074**
Depreciation, depletion and amortization	**(159)**
Other	**(5)**
Net Income	**$ 910**

Balance Sheet

As at December 31	2007
Current Assets	**$ 1,172**
Long-term Assets	**3,851**
Current Liabilities	**644**
Long-term Liabilities	**21**

Statement of Cash Flows

For the year ended December 31	2007
Cash From Operating Activities	**$ 885**
Cash (Used in) Investing Activities	**(322)**
Cash (Used in) From Financing Activities	**—**

H) Consolidated Statement of Cash Flows

Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP. Cash tax on sale of assets presented as investing activities under Canadian GAAP is presented as operating activities under U.S GAAP. Interest from early retirement of long-term debt included as a financing activity under Canadian GAAP is presented under operating activities under U.S GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31	**2007**	2006	2005
Dividends per share	**$ 0.800**	$ 0.375	$ 0.275

J) Recent Accounting Pronouncements

As of January 1, 2007, EnCana adopted, for U.S. GAAP purposes, FASB Interpretation No. 48 *"Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109"*. This Interpretation clarifies financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Guidance is also provided on the derecognition of previously recognized tax benefits and the classification of tax liabilities on the balance sheet. The adoption of this interpretation did not have a material impact on EnCana's Consolidated Financial Statements.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2008, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 157, *"Fair Value Measurements"*. SFAS 157 provides a common definition of fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This standard applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt, for U.S. GAAP purposes, measurement requirements under SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)"*. This standard also requires EnCana to measure the funded status of a plan as of the balance sheet date. The adoption of the change in measurement date should not have a material impact on EnCana's Consolidated Financial Statements.
- As of January 1, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 141(R), *"Business Combinations"*, which replaces SFAS 141. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard will impact EnCana's U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.
- As of January 1, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51"*. This standard requires a noncontrolling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP consolidated statement of earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the noncontrolling interest and to disclose these respective amounts. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Supplementary Oil and Gas Information – SFAS 69 (unaudited)

For the year ended December 31, 2007 (prepared in US$)

OTHER DISCLOSURES ABOUT OIL AND GAS ACTIVITIES

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including Statement of Financial Accounting Standard Number 69 ("SFAS 69").

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of price risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's Market Optimization interests.

Net Proved Reserves (unaudited)

Net Proved Reserves (EnCana Share After Royalties) (1,2) **Constant Pricing**	Natural Gas (billions of cubic feet)			Crude Oil and Natural Gas Liquids (millions of barrels)			
	Canada	United States	**Total**	Canada	United States	Ecuador	**Total**
2005							
Beginning of year	5,824	4,636	**10,460**	266.9	91.0	143.3	**501.2**
Revisions due to bitumen price	—	—	—	362.7 (3)	—	—	**362.7**
Beginning of year before bitumen revisions	5,824	4,636	**10,460**	629.6	91.0	143.3	**863.9**
Revisions and improved recovery	202	(260)	**(58)**	222.1	(3.2)	8.1	**227.0**
Extensions and discoveries	1,289	1,252	**2,541**	148.1	8.9	10.2	**167.2**
Purchase of reserves in place	7	76	**83**	—	0.4	—	**0.4**
Sale of reserves in place	(30)	(37)	**(67)**	(15.1)	(39.0)	—	**(54.1)**
Production	(775)	(400)	**(1,175)**	(52.2)	(5.0)	(26.6)	**(83.8)**
End of year	6,517	5,267	**11,784**	932.5	53.1	135.0 (4)	**1,120.6**
Developed	4,513	2,718	**7,231**	318.7	32.2	104.0	**454.9**
Undeveloped	2,004	2,549	**4,553**	613.8	20.9	31.0	**665.7**
Total	6,517	5,267	**11,784**	932.5	53.1	135.0	**1,120.6**
2006							
Beginning of year	6,517	5,267	**11,784**	932.5	53.1	135.0	**1,120.6**
Revisions and improved recovery	301	(88)	**213**	(39.0)	(1.1)	—	**(40.1)**
Extensions and discoveries	1,014	606	**1,620**	238.7	6.4	—	**245.1**
Purchase of reserves in place	—	68	**68**	—	0.3	—	**0.3**
Sale of reserves in place	(6)	(32)	**(38)**	(0.1)	—	(130.6)	**(130.7)**
Production	(798)	(431)	**(1,229)**	(52.7)	(4.7)	(4.4)	**(61.8)**
End of year	7,028	5,390	**12,418**	1,079.4 (5)	54.0	—	**1,133.4**
Developed	4,718	2,964	**7,682**	316.9	33.5	—	**350.4**
Undeveloped	2,310	2,426	**4,736**	762.5	20.5	—	**783.0**
Total	7,028	5,390	**12,418**	1,079.4 (5)	54.0	—	**1,133.4**
2007							
Beginning of year	7,028	5,390	**12,418**	1079.4	54.0	—	**1,133.4**
FCCL Partnership contribution	—	—	—	(398.0) (5)	—	—	**(398.0)**
Effective Jan 2, 2007	7,028	5,390	**12,418**	681.4	54.0	—	**735.4**
Revisions and improved recovery	87	78	**165**	75.5	3.6	—	**79.1**
Extensions and discoveries	949	827	**1,776**	155.8	5.9	—	**161.7**
Purchase of reserves in place	63	211	**274**	0.2	—	—	**0.2**
Sale of reserves in place	(24)	(7)	**(31)**	(0.2)	—	—	**(0.2)**
Production	(811)	(491)	**(1,302)**	(43.8)	(5.2)	—	**(49.0)**
End of year	7,292	6,008	**13,300**	868.9	58.3	—	**927.2**
Developed	4,868	3,368	**8,236**	289.5	37.0	—	**326.5**
Undeveloped	2,424	2,640	**5,064**	579.4	21.3	—	**600.7**
Total	7,292	6,008	**13,300**	868.9	58.3	—	**927.2**

(1) Definitions:
   a. "Net" reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.
   b. "Proved" reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.
   c. "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
   d. "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

(3) Reinstatement, as a result of year-end 2005 prices, of the Corporation's Foster Creek proved bitumen reserves that were deducted as a revision due to bitumen price at year-end 2004.

(4) The Corporation divested its Ecuadorian operations in 2006.

(5) Proved crude oil and NGLs reserves at December 31, 2006 include approximately 800 million barrels of bitumen, of which 796 million barrels was attributable to the Corporation's interests in Foster Creek and Christina Lake on that date. Effective January 2, 2007, these interests were contributed to FCCL in which the Corporation has a 50 percent interest. Accordingly, effective as at that date, the Corporation's reserves associated with those properties were reduced by 398 million barrels.

(6) In October, 2007, the Government of Alberta announced proposed changes to its provincial royalty regime effective January 1, 2009. In accordance with U.S. disclosure requirements, the reserves estimates at December 31, 2007 have been prepared using royalty regimes then in effect.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
($ millions)	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Future cash inflows	**95,778**	72,262	71,786	**38,398**	27,165	40,504	**—**	—	5,350
Less future:									
Production costs	**25,089**	20,471	16,765	**5,869**	4,123	3,262	**—**	—	2,093
Development costs	**10,171**	9,355	6,164	**6,943**	4,715	4,174	**—**	—	429
Asset retirement obligation payments	**3,320**	2,397	2,269	**532**	396	264	**—**	—	24
Income taxes	**12,871**	8,816	13,170	**7,375**	5,349	11,041	**—**	—	662
Future net cash flows	**44,327**	31,223	33,418	**17,679**	12,582	21,763	**—**	—	2,142
Less 10% annual discount for estimated timing of cash flows	**21,663**	14,627	13,281	**8,196**	6,128	10,291	**—**	—	574
Discounted future net cash flows	**22,664**	16,596	20,137	**9,483**	6,454	11,472	**—**	—	1,568

	Total		
($ millions)	**2007**	2006	2005
Future cash inflows	**134,176**	99,427	117,640
Less future:			
Production costs	**30,958**	24,594	22,120
Development costs	**17,114**	14,070	10,767
Asset retirement obligation payments	**3,852**	2,793	2,557
Income taxes	**20,246**	14,165	24,873
Future net cash flows	**62,006**	43,805	57,323
Less 10% annual discount for estimated timing of cash flows	**29,859**	20,755	24,146
Discounted future net cash flows	**32,147**	23,050	33,177

Changes in Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves	Canada			United States			Ecuador		
($ millions)	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Balance, beginning of year	**16,596**	20,137	12,178	**6,454**	11,472	7,488	**—**	1,568	1,202
Changes resulting from:									
Sales of oil and gas produced during the period	**(6,055)**	(5,970)	(5,720)	**(3,281)**	(2,373)	(2,436)	**—**	(142)	(604)
Discoveries and extensions, net of related costs	**3,796**	2,584	4,278	**1,591**	877	3,582	**—**	—	159
Purchases of proved reserves in place	**129**	—	26	**372**	69	237	**—**	—	—
Sales of proved reserves in place	**(2,933)**	(19)	(279)	**(15)**	(85)	(486)	**—**	(1,359)	—
Net change in prices and production costs	**11,077**	(5,797)	11,624	**4,818**	(7,636)	4,716	**—**	—	967
Revisions to quantity estimates	**823**	155	1,071	**830**	265	(700)	**—**	—	88
Accretion of discount	**2,087**	2,809	1,629	**924**	1,714	1,103	**—**	—	147
Previously estimated development costs incurred net of change in future development costs	**(667)**	(805)	(888)	**(907)**	(350)	162	**—**	(46)	(148)
Other	**(82)**	(174)	63	**(113)**	(381)	(64)	**—**	—	8
Net change in income taxes	**(2,107)**	3,676	(3,845)	**(1,190)**	2,882	(2,130)	**—**	(21)	(251)
Balance, end of year	**22,664**	16,596	20,137	**9,483**	6,454	11,472	**—**	—	1,568

	Total		
($ millions)	**2007**	2006	2005
Balance, beginning of year	**23,050**	33,177	20,868
Changes resulting from:			
Sales of oil and gas produced during the period	**(9,336)**	(8,485)	(8,760)
Discoveries and extensions, net of related costs	**5,387**	3,461	8,019
Purchases of proved reserves in place	**501**	69	263
Sales of proved reserves in place	**(2,948)**	(1,463)	(765)
Net change in prices and production costs	**15,895**	(13,433)	17,307
Revisions to quantity estimates	**1,653**	420	459
Accretion of discount	**3,011**	4,523	2,879
Previously estimated development costs incurred net of change in future development costs	**(1,574)**	(1,201)	(874)
Other	**(195)**	(555)	7
Net change in income taxes	**(3,297)**	6,537	(6,226)
Balance, end of year	**32,147**	23,050	33,177

Results of Operations and Capitalized Costs (unaudited)

Results of Operations

($ millions)	Canada 2007	Canada 2006	Canada 2005	United States 2007	United States 2006	United States 2005	Ecuador (1) 2007	Ecuador (1) 2006	Ecuador (1) 2005
Oil and gas revenues, net of royalties, transportation and selling costs	**7,362**	7,190	6,701	**4,065**	3,096	3,052	**—**	190	873
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**1,307**	1,220	981	**784**	723	616	**—**	48	269
Depreciation, depletion and amortization	**2,298**	2,146	1,961	**1,181**	869	712	**—**	84	234
Operating income (loss)	**3,757**	3,824	3,759	**2,100**	1,504	1,724	**—**	58	370
Income taxes	**1,114**	1,235	1,274	**809**	556	638	**—**	21	134
Results of operations	**2,643**	2,589	2,485	**1,291**	948	1,086	**—**	37	236

($ millions)	Other 2007	Other 2006	Other 2005	Total 2007	Total 2006	Total 2005
Oil and gas revenues, net of royalties, transportation and selling costs	**(1)**	2	—	**11,426**	10,478	10,626
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**18**	11	6	**2,109**	2,002	1,872
Depreciation, depletion and amortization	**69**	10	8	**3,548**	3,109	2,915
Operating income (loss)	**(88)**	(19)	(14)	**5,769**	5,367	5,839
Income taxes	**—**	—	—	**1,923**	1,812	2,046
Results of operations	**(88)**	(19)	(14)	**3,846**	3,555	3,793

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 and 2005 represents provisions which have been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments at February 28, 2006 and December 31, 2005.

Capitalized Costs

($ millions)	Canada 2007	Canada 2006	Canada 2005	United States 2007	United States 2006	United States 2005	Ecuador 2007	Ecuador 2006	Ecuador 2005
Proved oil and gas properties	**36,874**	31,546	27,074	**13,738**	9,796	7,753	**—**	—	1,926
Unproved oil and gas properties	**1,380**	1,700	1,998	**1,852**	1,221	870	**—**	—	18
Total capital cost	**38,254**	33,246	29,072	**15,590**	11,017	8,623	**—**	—	1,944
Accumulated DD&A	**19,286**	14,261	12,131	**3,783**	2,595	1,750	**—**	—	778
Net capitalized costs	**18,968**	18,985	16,941	**11,807**	8,422	6,873	**—**	—	1,166

($ millions)	Other 2007	Other 2006	Other 2005	Total 2007	Total 2006	Total 2005
Proved oil and gas properties	**—**	—	—	**50,612**	41,342	36,753
Unproved oil and gas properties	**297**	361	470	**3,529**	3,282	3,356
Total capital cost	**297**	361	470	**54,141**	44,624	40,109
Accumulated DD&A	**160**	98	222	**23,229**	16,954	14,881
Net capitalized costs	**137**	263	248	**30,912**	27,670	25,228

Costs Incurred (unaudited)

Costs Incurred	Canada			United States			Ecuador		
($ millions)	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Acquisitions									
Unproved	**28**	—	—	**1,048**	278	271	**—**	—	—
Proved	**61**	47	30	**1,565**	6	141	**—**	—	—
Total acquisitions	**89**	47	30	**2,613**	284	412	**—**	—	—
Exploration costs	**427**	403	817	**48**	236	264	**—**	1	15
Development costs	**3,309**	3,611	3,333	**1,871**	1,826	1,724	**—**	46	164
Total costs incurred	**3,825**	4,061	4,180	**4,532**	2,346	2,400	**—**	47	179

	Other			Total		
($ millions)	**2007**	2006	2005	**2007**	2006	2005
Acquisitions						
Unproved	**—**	—	—	**1,076**	278	271
Proved	**—**	—	—	**1,626**	53	171
Total acquisitions	**—**	—	—	**2,702**	331	442
Exploration costs	**60**	75	70	**535**	715	1,166
Development costs	**—**	—	—	**5,180**	5,483	5,221
Total costs incurred	**60**	75	70	**8,417**	6,529	6,829

Supplemental Financial Information – Financial Statistics (unaudited)

Financial Statistics	**2007**					2006				
($ millions, except per share amounts)	**Year**	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated										
Cash Flow (1)	**8,453**	1,934	2,218	2,549	1,752	7,161	1,761	1,894	1,815	1,691
Per share – Basic	**11.17**	2.58	2.96	3.36	2.28	8.73	2.22	2.34	2.19	1.99
– Diluted	**11.06**	2.56	2.93	3.33	2.25	8.56	2.18	2.30	2.15	1.96
Net Earnings	**3,959**	1,082	934	1,446	497	5,652	663	1,358	2,157	1,474
Per share – Basic	**5.23**	1.44	1.24	1.91	0.65	6.89	0.84	1.68	2.60	1.74
– Diluted	**5.18**	1.43	1.24	1.89	0.64	6.76	0.82	1.65	2.55	1.70
Operating Earnings (2)	**4,100**	849	1,032	1,369	850	3,271	675	1,078	824	694
Per share – Diluted	**5.36**	1.12	1.37	1.79	1.09	3.91	0.84	1.31	0.98	0.80
Continuing Operations										
Cash Flow from Continuing Operations (3)	**8,453**	1,934	2,218	2,549	1,752	7,043	1,742	1,883	1,839	1,579
Net Earnings from Continuing Operations	**3,884**	1,007	934	1,446	497	5,051	643	1,343	1,593	1,472
Per share – Basic	**5.13**	1.34	1.24	1.91	0.65	6.16	0.81	1.66	1.92	1.74
– Diluted	**5.08**	1.33	1.24	1.89	0.64	6.04	0.80	1.63	1.88	1.70
Operating Earnings – Continuing Operations (4)	**4,100**	849	1,032	1,369	850	3,237	672	1,064	841	660
Effective Tax Rates using										
Net Earnings	**19.4%**					27.3%				
Operating Earnings, excluding divestitures	**28.6%**					33.7%				
Canadian Statutory Rate	**32.3%**					34.7%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.930**	1.019	0.957	0.911	0.854	0.882	0.878	0.892	0.892	0.866
Period end	**1.012**	1.012	1.004	0.940	0.867	0.858	0.858	0.897	0.897	0.857
Cash Flow Information										
Cash from Operating Activities	**8,429**	2,193	2,180	2,148	1,908	7,973	1,697	1,655	2,325	2,297
Deduct (Add back):										
Net change in other assets and liabilities	**(16)**	(21)	1	(16)	20	138	90	21	38	(11)
Net change in non-cash working capital from continuing operations	**(8)**	280	(39)	(385)	136	3,343	39	(247)	1,508	2,044
Net change in non-cash working capital from discontinued operations	**—**	—	—	—	—	(2,669)	(193)	(13)	(1,036)	(1,427)
Cash Flow (1)	**8,453**	1,934	2,218	2,549	1,752	7,161	1,761	1,894	1,815	1,691
Cash Flow from Discontinued Operations	**—**	—	—	—	—	118	19	11	(24)	112
Cash Flow from Continuing Operations (3)	**8,453**	1,934	2,218	2,549	1,752	7,043	1,742	1,883	1,839	1,579

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions and the effect of a reduction in income tax rates.

(3) Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations, net change in non-cash working capital from discontinued operations and cash flow from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.

(4) Operating Earnings – Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax gain/loss on discontinuance, the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions and the effect of a reduction in income tax rates.

Supplemental Financial Information – Financial Statistics (unaudited)

Financial Statistics (continued)

Common Share Information

($ millions, except per share amounts)	2007 Year	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Year	2006 Q4	2006 Q3	2006 Q2	2006 Q1
Common Shares Outstanding (millions)										
Period end	**750.2**	750.2	749.5	752.8	761.3	777.9	777.9	800.1	815.8	836.2
Average – Basic	**756.8**	749.8	750.4	758.5	768.4	819.9	792.5	809.7	829.6	847.9
Average – Diluted	**764.6**	755.1	755.9	765.2	779.6	836.5	806.4	824.3	845.1	864.8
Price Range ($ per share)										
TSX – C$										
High	**71.21**	69.59	67.99	71.21	59.65	62.52	61.90	62.52	59.38	57.10
Low	**51.55**	60.89	59.33	57.61	51.55	44.96	48.28	48.35	49.51	44.96
Close	**67.50**	67.50	61.50	65.52	58.40	53.66	53.66	52.01	58.78	54.50
NYSE – US$										
High	**75.85**	75.85	65.18	66.87	51.49	55.93	53.90	55.93	53.31	50.50
Low	**42.38**	60.86	55.13	50.58	42.38	39.54	42.75	43.32	44.02	39.54
Close	**67.96**	67.96	61.85	61.45	50.63	45.95	45.95	46.69	52.64	46.73
Dividends Paid ($ per share)	**0.80**	0.20	0.20	0.20	0.20	0.375	0.10	0.10	0.10	0.075
Share Volume Traded (millions)	**1,250.9**	290.8	301.4	327.4	331.3	1,634.2	386.4	327.4	392.0	528.4
Share Value Traded										
(US$ millions weekly average)	**1,390.9**	1,489.3	1,414.4	1,479.5	1,209.5	1,516.2	1,447.9	1,272.9	1,484.8	1,850.5

Financial Metrics

	2007 Year	2006 Year
Net Debt to Capitalization	**34%**	27%
Net Debt to Adjusted EBITDA	**1.2x**	0.6x
Return on Capital Employed	**15%**	25%
Return on Common Equity	**21%**	34%

Net Capital Investment (unaudited)

Financial Statistics (continued)

Net Capital Investment

($ millions)	2007	2006
Capital		
Canada	$ 3,330	$ 3,352
United States	1,919	2,061
Other	106	106
Integrated Oil	580	632
Market Optimization	6	44
Corporate (1)	94	74
Capital from Continuing Operations	6,035	6,269
Acquisitions		
Property		
Canada	75	11
United States (2)	2,613	284
Other	—	15
Integrated Oil	14	21
Divestitures		
Property		
Canada	(54)	(59)
United States	(10)	(19)
Other (3)	(149)	—
Corporate (4)	(57)	—
Corporate		
Market Optimization	—	(244)
Other (5)	(211)	(367)
Net Acquisition and Divestiture Activity from Continuing Operations	2,221	(358)
Discontinued Operations		
Ecuador	—	(1,116)
Midstream	—	(1,531)
Net Capital Investment	$ 8,256	$ 3,264

(1) Includes capital expenditures on The Bow office project for $52 million in 2007.

(2) The Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in East Texas were acquired on November 20, 2007.

(3) Consists primarily of the sale of Mackenzie Delta assets which closed May 30, 2007 and sale of Australia assets which closed August 15, 2007.

(4) Sale of EnCana's office building project assets, The Bow, closed February 9, 2007.

(5) Sale of interests in Chad closed January 12, 2007 and sale of interests in Oman closed November 28, 2007. For 2006, the sale of shares of EnCanBrasil Limitada closed August 16, 2006.

Operating Statistics – Volumes (unaudited)

Operating Statistics – After Royalties

Production Volumes

	2007					2006				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations										
Produced Gas (MMcf/d)										
Canada	**2,221**	2,258	2,243	2,203	2,178	2,185	2,205	2,162	2,192	2,182
United States	**1,345**	1,464	1,387	1,303	1,222	1,182	1,201	1,197	1,169	1,161
Total Produced Gas	**3,566**	3,722	3,630	3,506	3,400	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids (bbls/d)										
North America										
Light and Medium Oil	**40,690**	40,462	40,345	40,025	41,946	44,440	41,972	46,454	43,672	45,680
Heavy Oil										
Foster Creek/Christina Lake	**26,814**	27,190	28,740	27,994	23,269	42,768	46,678	43,073	39,215	42,050
Other	**41,472**	41,621	40,882	40,897	42,500	45,858	41,913	43,287	44,572	53,822
Natural Gas Liquids (1)										
Canada	**11,316**	12,388	11,141	11,017	10,700	11,713	11,856	11,387	11,607	12,006
United States	**13,862**	14,476	15,275	13,483	12,175	12,494	12,250	12,520	12,793	12,415
Total Oil and Natural Gas Liquids	**134,154**	136,137	136,383	133,416	130,590	157,273	154,669	156,721	151,859	165,973
Total Continuing Operations (MMcfe/d)	**4,371**	4,539	4,448	4,306	4,184	4,311	4,334	4,299	4,272	4,339
Discontinued Operations										
Ecuador (bbls/d)	**–**	–	–	–	–	11,996	–	–	–	48,650
Total Discontinued Operations (MMcfe/d)	**–**	–	–	–	–	72	–	–	–	292
Total (MMcfe/d)	**4,371**	4,539	4,448	4,306	4,184	4,383	4,334	4,299	4,272	4,631

(1) Natural gas liquids include condensate volumes.

Downstream

	Year	Q4	Q3	Q2	Q1
Refinery Operations (2)					
Crude oil capacity (Mbbls/d)	**452**	452	452	452	452
Crude oil runs (Mbbls/d)	**432**	439	460	396	433
Crude utilization (%)	**96%**	97%	102%	88%	96%
Refined products (Mbbls/d)	**457**	465	484	421	457

(2) Represents 100% of the Wood River and Borger refinery operations.

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2007					2006				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations										
Produced Gas – Canada ($/Mcf)										
Price	**6.20**	6.35	5.36	6.76	6.36	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	**0.09**	0.03	0.10	0.11	0.10	0.10	0.05	0.09	0.08	0.18
Transportation and selling	**0.35**	0.35	0.34	0.36	0.36	0.35	0.33	0.37	0.35	0.34
Operating	**0.92**	1.03	0.83	0.90	0.91	0.79	0.82	0.78	0.77	0.79
Netback	**4.84**	4.94	4.09	5.39	4.99	4.96	4.67	4.35	4.51	6.35
Produced Gas – United States ($/Mcf)										
Price	**5.38**	5.03	4.68	5.73	6.24	6.35	5.65	6.04	6.08	7.70
Production and mineral taxes	**0.34**	0.29	0.38	0.17	0.53	0.49	0.50	0.43	0.22	0.85
Transportation and selling	**0.62**	0.64	0.60	0.65	0.61	0.54	0.60	0.57	0.50	0.49
Operating	**0.65**	0.70	0.52	0.71	0.67	0.65	0.68	0.59	0.70	0.64
Netback	**3.77**	3.40	3.18	4.20	4.43	4.67	3.87	4.45	4.66	5.72
Produced Gas – Total ($/Mcf)										
Price	**5.89**	5.83	5.10	6.38	6.32	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	**0.18**	0.14	0.21	0.14	0.26	0.24	0.21	0.21	0.13	0.41
Transportation and selling	**0.45**	0.46	0.44	0.47	0.45	0.42	0.42	0.44	0.40	0.40
Operating	**0.82**	0.90	0.72	0.83	0.82	0.74	0.77	0.71	0.74	0.74
Netback	**4.44**	4.33	3.73	4.94	4.79	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids – Canada ($/bbl)										
Price	**59.34**	73.39	62.87	55.21	43.26	51.12	44.79	55.95	55.19	48.84
Production and mineral taxes	**—**	—	—	—	—	—	—	—	—	—
Transportation and selling	**1.01**	0.96	1.80	0.74	0.54	0.67	0.58	0.74	0.73	0.61
Netback	**58.33**	72.43	61.07	54.47	42.72	50.45	44.21	55.21	54.46	48.23
Natural Gas Liquids – United States ($/bbl)										
Price	**59.83**	73.45	60.17	55.43	47.77	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	**4.28**	6.12	1.95	4.71	4.56	4.19	4.62	4.42	2.60	5.18
Transportation and selling	**0.01**	—	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**55.54**	67.33	58.21	50.71	43.20	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids – Total ($/bbl)										
Price	**59.61**	73.42	61.31	55.33	45.66	53.81	47.97	58.99	56.80	51.50
Production and mineral taxes	**2.36**	3.30	1.13	2.59	2.43	2.16	2.35	2.31	1.36	2.63
Transportation and selling	**0.46**	0.44	0.76	0.34	0.26	0.33	0.29	0.36	0.35	0.31
Netback	**56.79**	69.68	59.42	52.40	42.97	51.32	45.33	56.32	55.09	48.56
Crude Oil – Light and Medium ($/bbl)										
Price	**58.12**	71.48	61.18	53.36	46.40	51.76	43.28	56.50	61.62	45.31
Production and mineral taxes	**2.11**	2.20	1.89	2.19	2.14	2.16	2.15	2.13	2.47	1.92
Transportation and selling	**1.41**	1.30	1.53	1.36	1.43	0.98	0.61	1.32	0.65	1.29
Operating	**9.72**	11.09	9.51	9.28	9.00	8.62	9.01	10.00	7.36	8.06
Netback	**44.88**	56.89	48.25	40.53	33.83	40.00	31.51	43.05	51.14	34.04
Crude Oil – Total – excluding Foster Creek/Christina Lake ($/bbl)										
Price	**50.76**	59.93	54.68	47.02	41.42	44.83	37.65	51.37	55.58	35.39
Production and mineral taxes	**1.09**	1.12	1.01	1.16	1.06	1.11	1.11	1.14	1.28	0.92
Transportation and selling	**1.32**	1.23	1.47	1.31	1.27	0.91	0.60	1.27	0.76	1.00
Operating	**9.03**	10.52	8.68	8.85	8.06	7.69	8.59	8.73	6.84	6.67
Netback	**39.32**	47.06	43.52	35.70	31.03	35.12	27.35	40.23	46.70	26.80

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2007					2006				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations (continued)										
Crude Oil – Heavy										
– Foster Creek/Christina Lake ($/bbl)										
Price	**40.14**	45.58	42.86	39.40	33.28	36.49	39.32	37.19	46.53	23.08
Production and mineral taxes	**—**	—	—	—	—	—	—	—	—	—
Transportation and selling	**2.88**	2.75	2.10	3.62	3.07	2.64	2.74	2.64	3.38	1.80
Operating (1)	**14.46**	14.05	12.55	14.02	17.12	12.38	13.07	14.06	11.78	10.39
Netback	**22.80**	28.78	28.21	21.76	13.09	21.47	23.51	20.49	31.37	10.89
Crude Oil – Total ($/bbl)										
Price	**47.90**	56.23	51.50	44.92	39.19	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	**0.79**	0.83	0.74	0.84	0.77	0.77	0.74	0.81	0.88	0.66
Transportation and selling	**1.74**	1.62	1.64	1.94	1.75	1.40	1.11	1.74	1.54	1.24
Operating	**10.49**	11.43	9.72	10.27	10.54	9.09	10.05	10.20	8.34	7.82
Netback	**34.88**	42.35	39.40	31.87	26.13	30.57	25.04	35.99	40.86	21.04
Total Liquids – Canada ($/bbl)										
Price	**48.92**	57.92	52.50	45.83	39.50	42.53	37.55	49.21	51.91	32.17
Production and mineral taxes	**0.72**	0.74	0.66	0.76	0.70	0.70	0.67	0.73	0.80	0.61
Transportation and selling	**1.68**	1.56	1.66	1.84	1.67	1.35	1.06	1.67	1.48	1.19
Operating	**9.47**	10.20	8.78	9.29	9.60	8.33	9.21	9.39	7.63	7.17
Netback	**37.05**	45.42	41.40	33.94	27.53	32.15	26.61	37.42	42.00	23.20
Total Liquids ($/bbl)										
Price	**50.05**	59.60	53.37	46.81	40.25	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	**1.08**	1.32	0.81	1.16	1.04	0.99	0.99	1.05	0.96	0.96
Transportation and selling	**1.51**	1.39	1.47	1.65	1.51	1.24	0.98	1.52	1.35	1.10
Operating	**8.57**	9.19	7.87	8.41	8.81	7.66	8.47	8.58	7.01	6.64
Netback	**38.89**	47.70	43.22	35.59	28.89	33.82	28.25	39.22	43.12	25.17
Total ($/Mcfe)										
Price	**6.35**	6.57	5.80	6.65	6.40	6.48	5.93	6.31	6.46	7.22
Production and mineral taxes	**0.18**	0.15	0.19	0.15	0.24	0.22	0.20	0.20	0.13	0.36
Transportation and selling	**0.42**	0.42	0.41	0.43	0.42	0.37	0.37	0.40	0.36	0.35
Operating (2)	**0.93**	1.02	0.83	0.93	0.95	0.86	0.90	0.87	0.84	0.82
Netback	**4.82**	4.98	4.37	5.14	4.79	5.03	4.46	4.84	5.13	5.69

(1) Q1 2007 includes a prior year under accrual of operating costs of approximately $1.82/bbl.
(2) Year-to-date operating costs include costs related to long-term incentives of $0.05/Mcfe (2006 – $0.02/Mcfe).

Impact of Realized Financial Hedging

Natural Gas ($/Mcf)	**1.33**	1.49	1.65	1.24	0.92	0.47	0.91	0.82	0.66	(0.53)
Liquids ($/bbl)	**(3.05)**	(8.76)	(4.36)	(1.34)	2.34	(3.32)	(3.30)	(3.45)	(3.43)	(3.12)
Total ($/Mcfe)	**0.99**	0.96	1.21	0.96	0.82	0.25	0.60	0.53	0.40	(0.53)

Drilling Activity

The following tables summarize EnCana's gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations											
2007											
Canada	**120**	**96**	**7**	**6**	**—**	**—**	**127**	**102**	**180**	**307**	**102**
United States	**2**	**2**	**—**	**—**	**—**	**—**	**2**	**2**	**—**	**2**	**2**
Other	**—**	**—**	**—**	**—**	**4**	**3**	**4**	**3**	**—**	**4**	**3**
Total	**122**	**98**	**7**	**6**	**4**	**3**	**133**	**107**	**180**	**313**	**107**
2006											
Canada	281	230	7	7	7	6	295	243	128	423	243
United States	12	7	—	—	2	1	14	8	—	14	8
Other	—	—	2	1	4	1	6	2	—	6	2
Total	293	237	9	8	13	8	315	253	128	443	253
2005											
Canada	605	540	8	8	7	7	620	555	99	719	555
United States	7	6	—	—	9	7	16	13	1	17	13
Other	—	—	3	1	3	2	6	3	—	6	3
Total	612	546	11	9	19	16	642	571	100	742	571
Discontinued Operations											
Ecuador – 2005	—	—	2	1	3	2	5	3	—	5	3

Drilling Activity

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations											
2007											
Canada	**3,749**	**3,542**	**236**	**185**	**11**	**8**	**3,996**	**3,735**	**834**	**4,830**	**3,735**
United States	**809**	**641**	**—**	**—**	**1**	**1**	**810**	**642**	**102**	**912**	**642**
Total	**4,558**	**4,183**	**236**	**185**	**12**	**9**	**4,806**	**4,377**	**936**	**5,742**	**4,377**
2006											
Canada	2,799	2,639	139	103	25	24	2,963	2,766	855	3,818	2,766
United States	779	625	—	—	7	6	786	631	22	808	631
Total	3,578	3,264	139	103	32	30	3,749	3,397	877	4,626	3,397
2005											
Canada	3,503	3,229	277	243	12	11	3,792	3,483	932	4,724	3,483
United States	699	604	—	—	—	—	699	604	9	708	604
Total	4,202	3,833	277	243	12	11	4,491	4,087	941	5,432	4,087
Discontinued Operations											
Ecuador – 2006	—	—	7	6	1	1	8	7	—	8	7
Ecuador – 2005	—	—	28	15	3	1	31	16	—	31	16

(1) "Gross" wells are the total number of wells in which EnCana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating EnCana's working interest in each of its gross wells.

(3) At December 31, 2007, EnCana was in the process of drilling 25 gross wells (17 net wells) in Canada, 64 gross wells (49 net wells) in the United States and two gross wells (one net well) outside of North America.

Land

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total land holdings as at December 31, 2007.

	Developed		Undeveloped		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Continuing Operations						
Canada						
Alberta						
Fee	4,522	4,522	2,595	2,595	**7,117**	**7,117**
Crown	4,202	3,269	4,809	3,745	**9,011**	**7,014**
Freehold	253	155	187	154	**440**	**309**
	8,977	7,946	7,591	6,494	**16,568**	**14,440**
British Columbia						
Crown	1,118	958	4,144	3,398	**5,262**	**4,356**
Freehold	—	—	7	—	**7**	**—**
	1,118	958	4,151	3,398	**5,269**	**4,356**
Saskatchewan						
Fee	61	61	449	449	**510**	**510**
Crown	134	113	477	412	**611**	**525**
Freehold	15	11	32	30	**47**	**41**
	210	185	958	891	**1,168**	**1,076**
Manitoba						
Fee	3	3	261	261	**264**	**264**
Newfoundland and Labrador						
Crown	—	—	35	2	**35**	**2**
Nova Scotia						
Crown	—	—	498	175	**498**	**175**
Northwest Territories						
Crown	—	—	45	11	**45**	**11**
Total Canada	10,308	9,092	13,539	11,232	**23,847**	**20,324**

Land

Interest in Material Properties (continued)

(thousands of acres)	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
United States						
Colorado						
Federal/State Lands	199	185	720	664	**919**	**849**
Freehold	111	105	173	159	**284**	**264**
Fee	3	3	30	30	**33**	**33**
	313	293	923	853	**1,236**	**1,146**
Washington						
Federal/State Lands	—	—	655	298	**655**	**298**
Freehold	—	—	223	98	**223**	**98**
	—	—	878	396	**878**	**396**
Texas						
Federal/State Lands	7	4	472	452	**479**	**456**
Freehold	217	156	997	772	**1,214**	**928**
Fee	—	—	4	2	**4**	**2**
	224	160	1,473	1,226	**1,697**	**1,386**
Wyoming						
Federal/State Lands	143	87	636	452	**779**	**539**
Freehold	26	19	47	23	**73**	**42**
	169	106	683	475	**852**	**581**
Other						
Federal/State Lands	8	7	331	192	**339**	**199**
Freehold	3	3	981	978	**984**	**981**
	11	10	1,312	1,170	**1,323**	**1,180**
Total United States	717	569	5,269	4,120	**5,986**	**4,689**
International						
Qatar	—	—	2,161	1,080	**2,161**	**1,080**
Greenland	—	—	1,701	1,488	**1,701**	**1,488**
Brazil (7)	—	—	1,662	522	**1,662**	**522**
France	—	—	859	859	**859**	**859**
Azerbaijan	—	—	346	17	**346**	**17**
Australia	—	—	104	40	**104**	**40**
Total International	—	—	6,833	4,006	**6,833**	**4,006**
Total	11,025	9,661	25,641	19,358	**36,666**	**29,019**

(1) This table excludes approximately 4.3 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

(3) Crown/Federal/State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.

(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.

(5) Gross acres are the total area of properties in which EnCana has an interest.

(6) Net acres are the sum of EnCana's fractional interest in gross acres.

(7) In September 2007, EnCana agreed to sell its remaining interests in Brazil. The sale is subject to closing conditions and regulatory approvals, which are expected to be completed in the first half of 2008.

Corporate Information

CORPORATE OFFICERS [1]

Randall K. Eresman
President & Chief Executive Officer

John K. Brannan
Executive Vice-President
(President, Integrated Oil Division)

Sherri A. Brillon
Executive Vice-President, Strategic Planning & Portfolio Management

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

Kerry D. Dyte
Vice-President, General Counsel
& Corporate Secretary

Thomas G. Hinton
Treasurer
(Vice-President, Corporate Finance Group)

William A. Stevenson
Comptroller
(Vice-President, Corporate Finance Group)

Michael M. Graham
Executive Vice-President
(President, Canadian Foothills Division)

Sheila M. McIntosh
Executive Vice-President,
Corporate Communications

R. William Oliver
Executive Vice-President,
Business Development
(President, Midstream & Marketing Division)

Gerard J. Protti
Executive Vice-President,
Corporate Relations
(President, Offshore & International Division)

Ivor M. Ruste
Executive Vice-President
& Chief Risk Officer

Donald T. Swystun
Executive Vice-President
(President, Canadian Plains Division)

Hayward J. Walls
Executive Vice-President,
Corporate Services

Jeff E. Wojahn
Executive Vice-President
(President, USA Division)

(1) Divisional title in italics.

BOARD OF DIRECTORS

David P. O'Brien [4][7]
Chairman of the Board
Calgary, Alberta

Ralph S. Cunningham [2][3]
Houston, Texas

Patrick D. Daniel [1][5]
Calgary, Alberta

Ian W. Delaney [3][4]
Toronto, Ontario

Randall K. Eresman
Calgary, Alberta

Michael A. Grandin [3][4][6]
Calgary, Alberta

Barry W. Harrison [1][4]
Calgary, Alberta

Dale A. Lucas [1][5]
Calgary, Alberta

Ken F. McCready [2][5]
Calgary, Alberta

Valerie A. A. Nielsen [2][6]
Calgary, Alberta

Jane L. Peverett [1][5]
West Vancouver, British Columbia

Allan P. Sawin [1][3]
Edmonton, Alberta

Dennis A. Sharp [2][4]
Calgary, Alberta & Montreal, Quebec

James M. Stanford, O.C. [1][3][6]
Calgary, Alberta

Wayne G. Thomson [2][6]
Calgary, Alberta

Clayton H. Woitas
Calgary, Alberta

(1) Audit Committee
(2) Corporate Responsibility, Environment, Health and Safety Committee
(3) Human Resources and Compensation Committee
(4) Nominating and Corporate Governance Committee
(5) Pension Committee
(6) Reserves Committee
(7) Chairman of the Board, Chairman of Nominating and Corporate Governance Committee, and ex officio member of all other Board Committees

ENCANA HEAD OFFICE

1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
www.encana.com

Corporate Information

TRANSFER AGENTS & REGISTRAR

Common Shares

CIBC Mellon Trust Company
Calgary, Montreal & Toronto

BNY Mellon Shareowner Services
Jersey City, New Jersey

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline at 416-643-5500 or toll-free throughout North America at 1-800-387-0825, or via facsimile at 416-643-5501.

Mailing address

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9

Internet address

www.cibcmellon.com

TRUSTEE & REGISTRARS

CIBC Mellon Trust Company

Canadian Medium Term Notes
Calgary, Alberta
Toronto, Ontario

The Bank of New York

4.600% Senior Notes
4.750% Senior Notes
5.900% Senior Notes
6.500% Senior Notes
6.500% Senior Notes
6.625% Senior Notes
7.375% Senior Notes
7.650% Senior Notes
8.125% Senior Notes
New York, New York

The Bank of Nova Scotia Trust Company of New York

6.30% Senior Notes
7.20% Senior Notes
New York, New York

Deutsche Bank Trust Company Americas

5.80% Senior Notes
(EnCana Holdings Finance Corp.)
New York, New York

AUDITORS

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVE EVALUATORS

DeGolyer and MacNaughton
Dallas, Texas

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGES

Common Shares (ECA)

Toronto Stock Exchange
New York Stock Exchange

PRINCIPAL OPERATING SUBSIDIARIES & PARTNERSHIPS

	Percent Owned (1)
EnCana Marketing (USA) Inc.	100
EnCana Oil & Gas (USA) Inc.	100
EnCana Oil & Gas Partnership	100
FCCL Oil Sands Partnership	50
WRB Refining LLC	50

(1) Includes indirect ownership.

The above is not a complete list of all of the subsidiaries and partnerships of EnCana Corporation.

Investor Information

ANNUAL AND SPECIAL MEETING

Shareholders are invited to attend the Annual and Special Meeting being held on Tuesday, April 22, 2008 at 2 p.m. local time at the Four Seasons Hotel Toronto:

Regency Ballroom
21 Avenue Road
Toronto, Ontario, Canada

Those unable to do so are asked to sign and return the form of proxy that has been mailed to them.

ANNUAL INFORMATION FORM (FORM 40-F)

EnCana's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, EnCana's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

SHAREHOLDER ACCOUNT MATTERS

To change your address, transfer shares, eliminate duplicate mailings, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, etc., please contact CIBC Mellon Trust Company.

ENCANA WEBSITE www.encana.com

EnCana's website contains a variety of corporate and investor information including, among other information, the following:

- Current stock prices
- Annual and Interim Reports
- Information Circular
- News releases
- Investor presentations
- Dividend information
- Shareholder support information
- Corporate Responsibility Report

Additional information, including copies of the 2007 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations,
Corporate Communications
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
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Media inquiries should be directed to:

Alan Boras
Manager, Media Relations
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alan.boras@encana.com

ABBREVIATIONS

bbls	barrels
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
CBM	coalbed methane
CO_2	carbon dioxide
Mbbls	thousand barrels
MMbbls	million barrels
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MM	million
MMcf	million cubic feet
MMcfe	million cubic feet equivalent
NGLs	natural gas liquids
NOx	nitrogen oxide
SAGD	steam-assisted gravity drainage
SO_2	sulphur dioxide
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent

Mixed Sources
Product group from well-managed forests and other controlled sources
www.fsc.org Cert no. SGS-COC-2343

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EnCana
energy for people

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