Cenovus total proved reserves up 17% to 1.9 billion BOE

Cash flow for 2011 increases 36% to $3.3 billion

- Proved bitumen reserves at December 31, 2011 were about 1.5 billion barrels (bbls), a 26% increase over 2010.
- Best estimate bitumen economic contingent resources were 8.2 billion bbls, a 34% increase over 2010.
- Cenovus achieved production replacement of over 400% in 2011.
- The Board of Directors approved a dividend increase of 10% for the first quarter of 2012 resulting in a quarterly dividend of $0.22 per share.
- Foster Creek and Christina Lake combined oil sands production averaged nearly 67,000 barrels per day (bbls/d) net in 2011, a 13% increase over 2010. Christina Lake average production increased nearly 50% in 2011 compared with the previous year.
- Coker construction and start-up of the coker and refinery expansion (CORE) project at the Wood River Refinery was successfully completed.
- Cenovus met or exceeded all of the 2011 milestones it established.

"We achieved another strong year and are well on the way to reaching the goals established in our long-range plan," said Brian Ferguson, President & Chief Executive Officer of Cenovus. "Our financial results were excellent and we've enhanced the underlying value of the company through substantial reserves and resources growth. We've also announced a dividend increase of 10% for the first quarter of 2012 and we expect continued financial strength will allow our Board of Directors to place a priority on continuing to grow the dividend."

Financial & production summary

(for the period ended December 31) ($ millions, except per share amounts)	**2011 Q4**	2010 Q4	% change	**2011 Full Year**	2010 Full Year	% change
Cash flow[1]	**851**	645	32	**3,276**	2,412	36
Per share diluted	**1.12**	0.85		**4.32**	3.20	
Operating earnings[1]	**332**	147	126	**1,239**	799	55
Per share diluted	**0.44**	0.19		**1.64**	1.06	
Net earnings	**266**	78	241	**1,478**	1,081	37
Per share diluted	**0.35**	0.10		**1.95**	1.43	
Capital investment	**903**	701	29	**2,723**	2,115	29
Production (before royalties)						
Oil sands total (bbls/d)	**74,576**	60,789	23	**66,533**	59,045	13
Conventional oil and NGL total (bbls/d)	**69,697**	68,804	1	**67,706**	70,142	-3
Total oil and NGL production (bbls/d)	**144,273**	129,593	11	**134,239**	129,187	4
Natural gas (MMcf/d)	**660**	688	-4	**656**	737	-11

[1]Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.

Calgary, Alberta (February 15, 2012) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered excellent financial and operational results in 2011 and met or exceeded all the milestones it established. Cash flow for the year increased by more than one-third compared with 2010 and average oil production increased 4%. The company continues to advance its oil projects by drilling stratigraphic test wells, moving applications through the regulatory process and constructing expansions as it works toward the goal of 500,000 bbls/d of net oil production by the end of 2021.

"The success we achieved in 2011 is a direct result of the consistent, reliable and predictable approach we take to growing value for our shareholders," Ferguson said. "Despite the challenging economic environment, our financial results were stronger in 2011 than the previous year and we grew our oil production as well as substantially added to our reserves and contingent resources, which contributed to an increased net asset value. We're well positioned for another successful year in 2012."

The company's oil sands production increased by 13% in 2011 compared with the year earlier, due to production increases at Christina Lake and Foster Creek. The phase C expansion began producing at Christina Lake in the third quarter and benefited from accelerated start-up methods the company developed, which have patents pending. In addition, the implementation of learnings from past phases contributed to improved initial production from phase C. The increased production at Foster Creek was largely a result of improved plant efficiency and well performance. Conventional oil production decreased slightly in 2011 as gains made in the new Lower Shaunavon project were offset by production curtailments caused by flooding in southern Saskatchewan. Wildfires in northern Alberta impacted pipeline transportation from Pelican Lake.

Significant reserves and contingent resources additions

The 2011 independent reserves and contingent resources evaluation supports the company's long-term oil growth plans. At year-end 2011, Cenovus had proved bitumen reserves of about 1.5 billion bbls, an increase of 26% over 2010. This addition is primarily due to expansion of the development area at Christina Lake and improvements in overall recovery. Best estimate bitumen economic contingent resources increased 34% in 2011 to 8.2 billion bbls, primarily due to a successful 2011 stratigraphic test well drilling program. Proved light, medium and heavy oil and natural gas liquids (NGLs) reserves increased by about 4% and natural gas reserves declined by about 13%. Cenovus's overall proved finding and development (F&D) costs in 2011 were a competitive $5.95 per BOE, excluding changes in future development costs.

"Cenovus has an abundance of top-quality oil projects, supported by the independent reserves and contingent resources evaluation," Ferguson said. "We're working hard to continue assessing our undeveloped areas and applying for regulatory approvals to move forward these excellent growth opportunities. Our goal is to have a sizable portfolio of approved projects ready for development."

Capital investment expands oil opportunities
Cenovus met its planned 2011 capital guidance, investing about $2.7 billion in its operations, with more than three-quarters being spent on oil projects. About $900 million was invested at Foster Creek and Christina Lake on the expansion of the oil sands operations and the drilling of stratigraphic test wells. Additional funds were directed to stratigraphic test well drilling programs at the company's emerging oil sands projects to support the regulatory application process. Cenovus invested almost $320 million in its Pelican Lake oil operations, primarily on infill wells to progress the polymer flood as well as stratigraphic test wells and facility expansions. In addition, nearly $690 million was spent on conventional oil properties in southern Alberta and Saskatchewan, including Weyburn and the Lower Shaunavon and Bakken projects. Refining capital investment of nearly $400 million was directed primarily to the completion of coker construction at the Wood River Refinery's CORE project. Cenovus plans to spend between $3.1 billion and $3.4 billion on capital investment in 2012, primarily on its oil assets. The company continues to assess which assets will create the best return for shareholders and may consider further reducing natural gas capital investment if there is no recovery in natural gas prices.

"We have established a disciplined approach to capital investment at Cenovus," Ferguson said. "Our main priority is investing in our approved oil sands expansions and existing business operations. That's followed closely by our commitment to paying a meaningful dividend. The remaining cash flow is allocated to future projects which are expected to provide additional growth for the company."

Cash flow strengthens
Cash flow increased 36% in 2011 compared with the previous year to about $3.3 billion. Strong operating cash flow from the refineries as a result of significantly improved refining margins boosted the company's overall cash flow in 2011. Production growth at the oil sands operations as well as strong oil prices also contributed to the improved cash flow.

The 2012 corporate guidance, which the company released in December, remains unchanged and can be found at www.cenovus.com under the "Invest in us" section.

Progress in goal to double net asset value
Cenovus is on track to reach its goal of doubling net asset value (NAV) between 2010 and 2015. The company established a baseline illustrative NAV of $28 per share at December 2009 and has calculated the 2011 year-end NAV to be $37 per share. Cenovus uses a conservative approach to calculate NAV, based on the average of three independent external sources. Tracking NAV enables employees to measure their progress towards increasing the value underlying each share.

New oil transportation options
Cenovus continues to proactively assess various options to transport its oil and remains supportive of pipeline projects that will open up new markets and increase competition. The company is confident there will continue to be sufficient pipeline capacity to serve its planned increase in oil production. Cenovus has recently started shipping oil under a firm

service agreement on a pipeline that runs from Edmonton to the west coast. The firm service agreement is beneficial because it gives Cenovus the ability to negotiate longer term arrangements for markets in California and Asia. In addition to pipelines, Cenovus has also started using rail to ship oil from its Bakken operation in southern Saskatchewan.

Oil sands strategic transaction process ongoing
Cenovus is continuing its search for a strategic transaction to support development of the expanded Telephone Lake oil sands project. The company is considering recent interest in the opportunity from additional international parties.

"We received significant interest in this opportunity from around the world," said Ferguson. "It's in the best interest of our shareholders for us to take the necessary time to thoroughly review all possibilities. We will only undertake a transaction that has significant benefit for Cenovus shareholders."

The company filed an updated regulatory submission for the initial phases of the Telephone Lake project in December 2011. Cenovus is continuing its development work on the asset with an active stratigraphic test well drilling program and a dewatering pilot project. The 2011 independent reserves and contingent resources evaluation places best estimate bitumen economic contingent resources for the expanded Telephone Lake project at 2.1 billion bbls. Cenovus believes the expanded Telephone Lake project could ultimately be a cornerstone project like Foster Creek and Christina Lake.

IMPORTANT NOTE: Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS). See the Advisory for definitions of non-GAAP measures used in this news release.

Oil

Daily production[1]											
(Before royalties) (Mbbls/d)	2011					2010					2009[2]
	Full Year	**Q4**	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands											
Foster Creek	**55**	**55**	56	50	58	51	52	50	51	51	38
Christina Lake	**12**	**20**	10	8	9	8	9	8	8	7	7
Oil sands total	**67**	**75**	66	58	67	59	61	58	59	59	44
Conventional oil											
Pelican Lake	**20**	**21**	20	19	21	23	22	23	23	24	25
Weyburn	**16**	**17**	16	15	17	17	16	16	18	17	18
Other conventional oil & NGLs	**31**	**32**	31	29	32	31	31	31	29	32	32
Conventional total	**68**	**70**	67	64	71	70	69	70	70	72	74
Total oil & NGLs	**134**	**144**	133	122	137	129	130	128	129	131	119

[1] Totals may not add due to rounding.
[2] Does not include volumes from a property sold in the fourth quarter of 2009.

Oil sands

Foster Creek and Christina Lake

Cenovus's oil sands properties in northern Alberta offer opportunities for substantial growth. The Foster Creek and Christina Lake operations use steam-assisted gravity drainage (SAGD) to drill and pump the oil to the surface. These two projects are operated by Cenovus and jointly owned with ConocoPhillips.

Production

- Combined production at Foster Creek and Christina Lake increased 13% to nearly 67,000 bbls/d net in 2011 compared with the previous year. The production increase is even more significant quarter over quarter with 23% more oil sands production in the fourth quarter of 2011 compared with the same period a year earlier.
- Christina Lake production averaged nearly 12,000 bbls/d net in 2011, a 48% increase from the previous year. Christina Lake was producing an average of about 23,000 bbls/d net in December of 2011.
- The production increase at Christina Lake is primarily due to the start of production at phase C in the third quarter. The phase benefited from the success of a pilot to test new methods to accelerate the initial start-up of production from well pairs. These new methods enable the wells to start producing at peak rates faster with less initial steam. Other technological and operational enhancements also contributed to increased production at Christina Lake.

- Foster Creek produced an average of nearly 55,000 bbls/d net in 2011, 7% more than the 2010 average.
- About 11% of current production at Foster Creek comes from 41 wells using Cenovus's Wedge Well™ technology. These single horizontal wells, drilled between existing SAGD well pairs, reach oil that would otherwise be unrecoverable. The company's Wedge Well™ technology has the potential to increase overall recovery from the reservoir by as much as 10%, while reducing the steam to oil ratio (SOR). Christina Lake is also starting to benefit from the use of Wedge Well™ technology with four of these wells now producing.

Expansions

- At Christina Lake, construction of phase D is more than 70% complete and production is expected in the fourth quarter of this year. Construction of phase E is more than 30% complete, with initial production anticipated in the fourth quarter of 2013. Ground preparation also continues for phase F.
- An application for an amendment to the existing Christina Lake regulatory approval was submitted in December to add cogeneration facilities to the operation. The application also includes an anticipated increase in gross production capacity of 10,000 bbls/d at phase F and at phase G, resulting in each phase having a gross production capacity of 50,000 bbls/d. Christina Lake is now expected to reach gross production capacity of 278,000 bbls/d by the end of 2019.
- At Foster Creek, work continues on the next three expansion phases, F, G and H. Ground preparation is now complete for all three phases and at phase F, site preparation and the installation of pipe racks continue to progress on schedule. With the completion of phases F, G and H and the addition of future phases, Foster Creek is expected to reach gross production capacity of between 290,000 bbls/d and 310,000 bbls/d.
- Combined capital investment at Foster Creek and Christina Lake was about $900 million in 2011, a 45% increase compared with 2010. This includes spending on the expansion phases and stratigraphic test wells.

Operating costs

- Operating costs at Foster Creek averaged $11.34/bbl in 2011, a 9% increase from $10.40/bbl the previous year. Non-fuel operating costs at Foster Creek were $9.15/bbl in 2011 compared with $8.12/bbl in 2010, a 13% increase. The increases were mostly due to higher staffing levels, increased repairs and maintenance costs as well as higher workover costs.
- Operating costs at Christina Lake were $20.20/bbl in 2011, a 23% increase from $16.47/bbl the previous year. Non-fuel operating costs at Christina Lake were $17.16/bbl in 2011 compared with $13.45/bbl in 2010, a 28% increase. The increase was largely due to higher staffing costs in preparation for operations to begin at phase C and future expansions. There were also increased repairs and maintenance costs. As production from new phases continues to increase to full capacity, the company expects a decrease in per barrel operating costs.

- Operating costs at both Foster Creek and Christina Lake in 2012 are expected to be consistent with the estimates provided in the company's guidance released in December.

Steam to oil ratios (SORs)

- Cenovus continued to achieve some of the best SORs in the industry with ratios of approximately 2.2 at Foster Creek and 2.3 at Christina Lake for a combined SOR of about 2.2 in 2011. The SOR at Christina Lake in 2011 was slightly higher than the previous year due to the increased need for steam to start-up phase C. As production climbs, the company expects the SOR to decrease.
- SOR measures the number of barrels of steam needed for every barrel of oil produced, with Cenovus having one of the lowest ratios in the industry. A lower SOR means less natural gas is used to create the steam, which results in reduced capital and operating costs, fewer emissions and lower water usage.

New bitumen blend stream

In the fourth quarter, Cenovus launched a new stand alone Christina Lake bitumen blend stream called Christina Dilbit Blend (CDB), which is for sale at the Hardisty hub. CDB is a heavy stream with a price that's currently at a discount to the Western Canadian Select (WCS) heavy benchmark. The initial sales of the CDB stream have resulted in wider discounts attributable to often lengthy refinery testing and approval requirements for any new crude. It is expected that the CDB differential to WCS will narrow as it gains acceptance with a wider base of refining customers.

Future projects

Cenovus has an enormous opportunity to deliver increased shareholder value through production growth from its oil sands assets in the Athabasca region of northern Alberta, most of which are undeveloped. The company has identified 10 emerging projects and continues to assess its resources to prioritize development plans and support regulatory applications. Cenovus currently has projects with total expected gross production of 400,000 bbls/d moving through the regulatory process.

- A joint regulatory application and environmental impact assessment was submitted in the fourth quarter for a commercial SAGD project at Grand Rapids in the Greater Pelican Region. A pilot has been underway for more than a year and a second well pair is now being drilled. First production from the commercial project is anticipated for 2017. Grand Rapids has the potential to reach production capacity of 180,000 bbls/d.
- A revised joint regulatory application and environmental impact assessment for the Telephone Lake project in the Borealis Region was also submitted in the fourth quarter. The application updates the expected production capacity to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007.
- The regulatory application for the Narrows Lake project, jointly owned with ConocoPhillips, is being reviewed by the regulators and Cenovus anticipates receiving approvals by mid-2012. The application includes the option of using a combination of SAGD and solvent aided process (SAP) for oil production. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d, with initial production expected in 2016.

Conventional oil

Pelican Lake

Cenovus produces heavy oil from the Wabiskaw formation at its wholly-owned Pelican Lake operation in the Greater Pelican Region, about 300 kilometres north of Edmonton. While this property produces conventional heavy oil, it's managed as part of Cenovus's oil sands segment. Since 2006, polymer has been injected along with the waterflood to enhance production from the reservoir. Based on reservoir performance of the polymer flood, the company has initiated a new multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d by the end of 2016.

- Pelican Lake produced approximately 20,000 bbls/d in 2011, an 11% decrease in production compared with 2010 partially due to curtailment of production in the second quarter caused by wildfires restricting pipeline transportation as well as scheduled maintenance and expected natural declines.
- Operating costs at Pelican Lake averaged $14.86/bbl in 2011, a 17% increase from $12.71/bbl in 2010. The increase is mainly due to increased staffing levels, higher workover and chemical costs for the expanded polymer flood, and lower production.
- Capital spending at Pelican Lake in 2011 was $317 million, about triple the amount invested in 2010. Spending was primarily related to infill drilling and facility expansions for the polymer flood. This investment is expected to result in increased production in 2012.

Other conventional

In addition to Pelican Lake, Cenovus has extensive oil operations in Alberta and Saskatchewan. These include the established Weyburn operation that uses CO_2 to enhance recovery, the emerging Bakken and Lower Shaunavon tight oil assets in southern Saskatchewan as well as established properties in southern Alberta. Cenovus is anticipating oil production from these properties to reach between 65,000 bbls/d and 75,000 bbls/d by the end of 2016.

- The Weyburn operation produced more than 16,000 bbls/d net in 2011, slightly less than the previous year. Flooding in the second quarter had a negative impact on production.
- Lower Shaunavon production averaged approximately 2,000 bbls/d in 2011, more than double 2010 production. Average December production at Lower Shaunavon was nearly 3,500 bbls/d. At the end of the year, Cenovus had 73 horizontal wells and one vertical well producing.
- The company's Bakken operation had average oil production of more than 1,500 bbls/d in 2011, including royalty interest volumes, and a December average production rate of more than 2,700 bbls/d. Cenovus was operating 22 wells in the Bakken project at the end of 2011.
- Late last year, Cenovus began using rail as a transportation option to send some of its Bakken production to market.
- Operating costs for Cenovus's conventional oil and liquids operations, excluding Pelican Lake, increased 16% to $13.84/bbl in 2011 compared with 2010. This was mainly due to higher electricity costs, increased repairs and maintenance and workover activity, higher staffing costs as well as increased trucking and waste handling costs.

Natural Gas

(Before royalties) (MMcf/d)	Daily production										
	2011					2010					2009
	Full Year	**Q4**	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas[1]	**656**	**660**	656	654	652	737	688	738	751	775	837

[1] 2010 production includes a contribution from non-core assets sold in the third quarter of 2010.

Cenovus has a solid base of established, reliable natural gas properties in Alberta. These assets are an important component of the company's financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations, because natural gas fuels the company's oil sands and refining operations.

- Natural gas production in 2011 was approximately 656 million cubic feet per day (MMcf/d), an 11% decline from the previous year. Nearly one-third of this decline was attributable to the sale of non-core natural gas properties in 2010. The remainder of the decrease was due to the company shifting capital to oil development as well as expected natural production declines.
- Cenovus's average realized sales price for natural gas, including hedges, was $4.52 per thousand cubic feet (Mcf) in 2011 compared with $5.16 per Mcf in 2010.
- The company invested $116 million in its natural gas properties in 2011. These assets generated $777 million of operating cash flow, providing an excess of $661 million of the capital spent on them, helping to fund development of the company's oil assets.
- Cenovus plans to manage declines in natural gas volumes, targeting a long-term production level of between 400 MMcf/d and 500 MMcf/d to match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining

Cenovus's refining operations include the Wood River Refinery in Illinois and the Borger Refinery in Texas, which are jointly owned with the operator, ConocoPhillips.

- Construction of the 65,000 bbls/d coker at the CORE project was completed in the fourth quarter and the start-up activities were accomplished successfully and safely. The project was within 10% of its original budget with capital expenditures of approximately US$3.8 billion (US$1.9 billion net to Cenovus).
- The CORE project has resulted in a clean product yield increase of 5% at the Wood River Refinery.
- Once testing of the CORE project is complete, total processing capability of heavy Canadian crudes will be dependent upon the quality of available crudes and will be optimized to maximize economic benefit. The total heavy crude processing capability is expected to be in the range of 200,000 bbls/d to 220,000 bbls/d. Combined with the 35,000 bbls/d heavy crude oil refining capacity at the Borger Refinery, the total heavy

crude oil refining capacity of the two refineries is expected to be approximately 235,000 bbls/d to 255,000 bbls/d.

- Operating cash flow from the refineries was $976 million in 2011, compared with $67 million in 2010. The increased operating cash flow was due to significantly improved refining margins as a result of higher global refined product prices. The refineries also benefited from discounted feedstock costs due to a surplus of oil available in the region and discounts on heavy crude oil.
- Cenovus's operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's 2011 refining operating cash flow would have been $95 million lower than under FIFO, compared with $19 million lower in 2010.
- For the full year, the company's refining business generated $585 million of operating cash flow in excess of the $391 million of capital expenditures, providing additional funds for the development of upstream oil assets.
- The refining business achieved fourth quarter operating cash flow of $241 million compared with $129 million during the same quarter of 2010.
- Cenovus expects first quarter 2012 refining operating cash flow to be in the range of $150 million to $250 million.
- In 2011, the two refineries produced approximately 419,000 bbls/d of refined products, an increase of 3% compared with the previous year.
- Refinery crude utilization averaged 89% or 401,000 bbls/d of crude throughput in 2011, an increase from the 86%, or 386,000 bbls/d of throughput in 2010.
- Almost one-third of the total crude feedstock at these two refineries was heavy oil from Canada. Both the amount and proportion of heavy crude oil processed is expected to increase in 2012 due to the implementation of CORE.
- Despite some weather-related outages during the year, crude utilization improved in 2011 compared with utilization rates in 2010, which were affected by scheduled turnarounds as well as refinery optimization activities in response to weak market conditions.

2011 Reserves and Contingent Resources

All of Cenovus's reserves and resources are evaluated each year by independent qualified reserves evaluators.

- At year end 2011, Cenovus had total proved reserves of 1.9 billion barrels of oil equivalent (BOE), an increase of 17% compared with 2010.
- Proved bitumen reserves increased 26% in 2011 compared with 2010, to about 1.5 billion bbls. This increase was primarily due to expansion of the development area at Christina Lake and improvements in overall recovery at both Foster Creek and Christina Lake.
- Best estimate bitumen economic contingent resources increased 34% in 2011 to 8.2 billion bbls. This growth was driven primarily by a successful 2011 stratigraphic test well drilling program.
- Proved light, medium and heavy oil reserves increased by about 4%, as positive revisions outpaced production.

- Proved natural gas reserves declined by about 13% in 2011 as production outpaced additions and positive technical revisions.
- Cenovus's proved F&D costs in 2011 were $5.95 per BOE, excluding changes in future development costs.
- Cenovus achieved production replacement of over 400% in 2011.
- The overall proved reserves life index is approximately 22.4 years, a 21% increase compared with 2010. The depth of the company's bitumen assets is extensive with a bitumen proved reserves life index of 60 years, a 12% increase. The oil and NGLs proved reserves life is 12.7 years.

Proved reserves reconciliation				
(Before royalties)	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
Start of 2011	1,154	169	111	1,390
Extensions & improved recovery	256	16	13	50
Technical revisions	69	2	1	29
Economic factors	-	1	-	-28
Acquisitions	-	-	-	-
Divestitures	-	-	-	-
Production[1]	-24	-13	-10	-238
End of 2011	1,455	175	115	1,203
% Change	26	4	4	-13
Developed	168	120	90	1,179
Undeveloped	1,287	55	25	24
Total proved	1,455	175	115	1,203
Total probable	490	109	51	391
Total proved plus probable	1,945	284	166	1,594

[1]Production used for the reserves reconciliation differs from reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production. See the Advisory – Oil and Gas Information for more information about royalty interest production.

Proved reserves costs[1]			
(Before royalties)	**2011**	2010	3 Year
Capital Investment ($ millions)			
Finding and Development	**2,175**	1,374	4,633
Finding, Development and Acquisitions	**2,244**	1,422	4,898
Proved Reserves Additions[2] (MMBOE)			
Finding and Development	**366**	376	943
Finding, Development and Acquisitions	**366**	377	943
Proved Reserves Costs[2] ($/BOE)			
Finding and Development[3]	**5.95**	3.65	4.91
Finding, Development and Acquisitions[4]	**6.14**	3.77	5.19

[1] Finding and Development Cost calculations presented in the table do not include changes in future development costs. See the Advisory – Finding and Development Costs for a full description of the methods used to calculate Finding and Development Costs which include the change in future development costs.
[2] Reserves Additions for Finding and Development are calculated by summing technical revisions, extensions and improved recovery, discoveries and economic factors. Reserves Additions for Finding, Development and Acquisitions are calculated by summing Reserves Additions for Finding and Development and additions from acquisitions. See the Advisory – Oil and Gas Information.
[3] Finding and Development Costs without changes in future development costs is equal to Finding and Development Capital Investment divided by Finding and Development Reserves Additions.
[4] Finding, Development and Acquisitions without changes in future development costs is equal to Finding, Development and Acquisitions Capital Investment divided by Finding, Development and Acquisitions Reserves Additions.

Bitumen contingent resources			
(Before royalties)			
Economic Contingent Resources[1]	**Bitumen (billion bbls)**		
	2011	**2010**	**% Change**
Low Estimate	**6.0**	4.4	36
Best Estimate	**8.2**	6.1	34
High Estimate	**10.8**	8.0	35

[1] For the definition of contingent resources, economic contingent resources and low, best and high estimate and a description of the contingencies associated with Cenovus's economic contingent resources, please see the Advisory – Oil and Gas Information. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Financial

Dividend

The Cenovus Board of Directors has approved a 10% increase in the first quarter 2012 dividend to $0.22 per share, payable on March 30, 2012 to common shareholders of record as of March 15, 2012. Based on the February 14, 2012 closing share price on the Toronto Stock Exchange of $38.60, this represents an annualized yield of about 2.3%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to the dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging strategy

The natural gas and crude oil hedging strategy helps Cenovus to achieve more predictability around cash flow and safeguard its capital program. The strategy allows the company to financially hedge up to 75% of this year's expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the two following years. The company has Board approval for fixed price hedges on as much as 50% of net liquids production this year and 25% of net liquids production for each of the following two years.

In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 125 MMcf/d of natural gas is expected to be consumed at the company's SAGD and refinery operations, which is offset by the gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's hedge positions at December 31, 2011 include:

- approximately 65% of expected 2012 natural gas production hedged; 130 MMcf/d at an average NYMEX price of US$5.96/Mcf and 127 MMcf/d at an average AECO price of C$4.50/Mcf, plus 125 MMcf/d of internal usage
- approximately 30% of expected 2012 oil production hedged, with 24,800 bbls/d at a WTI price of US$98.72/bbl and an additional 24,500 bbls/d at an average WTI price of C$99.47/bbl
- 166 MMcf/d of natural gas hedged for 2013 at an average NYMEX price of US$4.64/Mcf, plus internal usage.

Financial highlights

- Cash flow in 2011 was $3.3 billion, or $4.32 per share diluted, compared with $2.4 billion, or $3.20 per share diluted, a year earlier.
- Operating earnings in 2011 were $1.2 billion, or $1.64 per share diluted, compared with about $800 million, or $1.06 per share diluted, for the same period last year.
- Earnings in 2011 reflect an after-tax impairment of property plant and equipment of $30 million, primarily attributable to the writedown of a catalytic cracking unit at the Wood River Refinery, compared with an after-tax charge of $9 million in 2010.
- Both cash flow and operating earnings were higher in 2011 primarily due to improved operating cash flow from the company's refineries and higher average crude oil sales prices and volumes.
- Cenovus's realized after-tax hedging gains were $51 million in 2011. Cenovus received an average realized price, including hedging, of $69.99/bbl for its oil in 2011, compared with $62.61/bbl during 2010. The average realized price, including hedging, for natural gas in 2011 was $4.52/Mcf, compared with $5.16/Mcf in 2010.
- Cenovus recorded income tax expense of $729 million, a $506 million increase over the previous year largely because of increased refining income, which is subject to tax at the higher U.S. rate.
- Cenovus's net earnings for the year were $1.5 billion compared with $1.1 billion in 2010. Net earnings were positively affected by an unrealized after-tax hedging gain of $134 million, strong refining results and higher average sales prices and volumes for crude oil.

- Capital investment during the year was $2.7 billion, a 29% increase compared with 2010 as the company continues to advance development of its oil opportunities.
- General and administrative expenses increased about 20% in 2011 compared with 2010. This is primarily because of the need for more staff as the company grows, which results in increased salaries and benefits, long-term incentive expense and office costs.
- Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At December 31, 2011, the company's debt to capitalization ratio was 27% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.0 times.

Earnings reconciliation summary

(for the period ended December 31) ($ millions, except per share amounts)	2011 Q4	2010 Q4	2011 Full Year	2010 Full Year
Net earnings Add back (losses) & deduct gains: Per share diluted	**266** **0.35**	78 0.10	**1,478** **1.95**	1,081 1.43
Unrealized mark-to-market hedging gain (loss), after-tax	**-180**	-197	**134**	34
Non-operating foreign exchange gain (loss), after-tax	**25**	118	**14**	153
Divestiture gain (loss), after-tax	**89**	-2	**91**	83
Gain on asset acquisition	**-**	12	**-**	12
Operating earnings Per share diluted	**332** **0.44**	147 0.19	**1,239** **1.64**	799 1.06

Oil sands project schedule[1]				
Project phase	**Actual/expected gross production capacity (bbls/d)**	**Expected cumulative gross production capacity (bbls/d)**	**Regulatory application submissions[2]**	**First production target[2,3]**
Foster Creek[4]				
A-E[5]	120,000	120,000	Q1 1999	Q1 2002
F[5]	45,000	165,000	Q2 2009	2014
G[5]	40,000	205,000	Q2 2009	2015
H[5]	40,000	245,000	Q2 2009	2016
Future phases	45,000 – 65,000	290,000 – 310,000	2013	2017
Christina Lake[4]				
A-B[5]	18,000	18,000	Q3 1998	Q4 2002
C[5]	40,000	58,000	Q3 2007	Q3 2011
D[5]	40,000	98,000	Q3 2007	Q4 2012
E[5]	40,000	138,000	Q4 2009	Q4 2013
F[5]	50,000 (previously 40,000)	188,000 (previously 178,000)	Q4 2009	2016
G[5]	50,000 (previously 40,000)	238,000 (previously 218,000)	Q4 2009	2017
H	40,000	278,000 (previously 258,000)	2013	2019
Narrows Lake[4]				
A-C	130,000	130,000	Q2 2010	2016
Grand Rapids				
A-C	180,000	180,000	Q4 2011	2017
Telephone Lake				
A-B	90,000	90,000	Q4 2011	TBD

[1] Timelines are subject to regulatory and partner approvals.
[2] Future dates are company forecasts, please see the Advisory – Forward-Looking Information.
[3] There is an anticipated ramp up period of approximately 12 to 18 months following first production although the accelerated start-up process being tested at Christina Lake is currently showing improvements to that timing.
[4] Properties 50% owned by ConocoPhillips.
[5] Approved by regulator.

Conference call today

9:00 a.m. Mountain Time (11:00 a.m. Eastern Time)

Cenovus will host a conference call today, February 15, 2012, starting at 9:00 a.m. MT (11:00 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 2:00 p.m. MT on February 15, 2012, until midnight February 22, 2012, by dialing 855-859-2056 or 416-849-0833 and entering conference passcode 44449209. A live audio webcast of the conference call will also be available via www.cenovus.com. The webcast will be archived for approximately 90 days.

ADVISORY

Effective January 1, 2011, Cenovus adopted International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board. Cenovus's 2011 consolidated financial statements and the 2010 comparative information have been prepared under IFRS. Refer to our Consolidated Financial Statements and associated Management's Discussion and Analysis (MD&A) for further information.

NON-GAAP MEASURES

This news release contains references to non-GAAP measures as follows:

- Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains, less losses on risk management activities and is used to provide a consistent measure of the cash generating performance of the company's assets and improves the comparability of Cenovus's underlying financial performance between periods.
- Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim Consolidated Financial Statements.
- Operating earnings is defined as net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the gain on asset acquisition, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, the after-tax foreign exchange gain/loss on settlement of intercompany transactions, after-tax gains or losses on divestiture of assets, deferred income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. Management views operating earnings as a better measure of performance than net earnings because the excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Debt to capitalization and debt to adjusted EBITDA are two ratios that management uses to steward the company's overall debt position as measures of the company's

overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion, excluding any amounts with respect to the partnership contribution payable and receivable. Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Adjusted EBITDA is defined as adjusted earnings before finance costs, interest income, income taxes, depreciation, depletion and amortization, exploration expense, unrealized gain or loss on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss.

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. For further information, refer to Cenovus's most recent MD&A available at www.cenovus.com.

FINDING AND DEVELOPMENT COSTS
Finding and development costs disclosed in this news release do not include the change in estimated future development costs. Cenovus uses finding and development costs without changes in estimated future development costs as an indicator of relative performance to be consistent with the methodology accepted within the oil and gas industry.

Finding and development costs for proved reserves, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $13.99/BOE for the year ended December 31, 2011, $10.55/BOE for the year ended December 31, 2010 and averaged $13.05/BOE for the three years ended December 31, 2011. Finding and development costs for proved plus probable reserves, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $10.69/BOE for the year ended December 31, 2011, $9.78/BOE for the year ended December 31, 2010 and averaged $12.37/BOE for the three years ended December 31, 2011. These finding and development costs were calculated by dividing the sum of exploration costs, development costs and changes in future development costs in the particular period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period and the change during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

NET ASSET VALUE
With respect to the particular year being valued, the net asset value (NAV) disclosed herein is based on the number of issued and outstanding Cenovus shares adjusted for the dilutive effect of stock options or other contracts as at December 31. We calculate NAV as an average of (i) our average trading price for the month of December, (ii) an average of net asset values published by external analysts in December following the announcement of our budget forecast, and (iii) an average of two net asset values based primarily on discounted cash flows of independently evaluated reserves, resources and downstream data and using internal corporate costs, with one based on constant prices and costs and one based on forecast prices and costs.

OIL AND GAS INFORMATION

The reserves and resources data is presented as at December 31, 2011 using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2012 forecast prices and costs. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalties volumes presented in the reserves reconciliation (i) do not include reserves associated with this production and (ii) the production differs from other publicly reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production.

Certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE 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 represent value equivalency at the wellhead.

The estimates of bitumen contingent resources were prepared effective December 31, 2011 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

- Contingent Resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development.
- Economic Contingent Resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2011 reserves evaluation, which comply with NI 51-101 requirements.
- Best Estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent confidence level that the actual quantities recovered will equal or exceed the estimate.

Contingent resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. The contingencies applicable to our contingent resources are not categorized as economic and for the most part are due to regulatory approval of development projects at our properties, partner sanction and adequate capital funding within five years.

FORWARD-LOOKING INFORMATION

This news release contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this news release is identified by words such as “anticipate”, “believe”, “expect”, “plan”, “forecast”, “target”, “project”, “could”, “focus”, “vision”, “goal”, “proposed”, “scheduled”, “outlook”, “potential”, “may” , “looking forward to”, or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including technology and procedures to reduce our environmental impact, and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the estimation of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; 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 producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta’s regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our most recent AIF/Form 40-F, "Risk Management" in our current MD&A and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and our website at www.cenovus.com.

Cenovus Energy Inc.

Cenovus Energy Inc. is a Canadian integrated oil company. It is committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. Operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface, and established natural gas and oil production in Alberta and Saskatchewan. The company also has 50% ownership in two U.S. refineries. Cenovus shares trade under the symbol CVE, and are listed on the Toronto and New York stock exchanges. Its enterprise value is approximately $33 billion. For more information, visit www.cenovus.com.

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CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended December 31,		Three Months Ended		Twelve Months Ended	
($ millions, except per share amounts)		**2011**	2010 [1]	**2011**	2010 [1]
Gross Sales	*(Note 1)*	**4,480**	3,471	**16,185**	13,090
Less: Royalties		**151**	108	**489**	449
Revenues		**4,329**	3,363	**15,696**	12,641
Expenses	*(Note 1)*				
Purchased product		**2,531**	2,040	**9,090**	7,551
Transportation and blending		**396**	270	**1,369**	1,065
Operating		**386**	307	**1,406**	1,286
Production and mineral taxes		**9**	8	**36**	34
(Gain) loss on risk management	*(Note 21)*	**230**	198	**(248)**	(324)
Depreciation, depletion and amortization		**383**	324	**1,295**	1,302
Exploration expense		**-**	3	**-**	3
General and administrative		**89**	89	**295**	246
Finance costs	*(Note 5)*	**112**	120	**447**	498
Interest income	*(Note 6)*	**(30)**	(34)	**(124)**	(144)
Foreign exchange (gain) loss, net	*(Note 7)*	**(30)**	(28)	**26**	(51)
(Gain) loss on divestiture of assets	*(Note 14)*	**(104)**	3	**(107)**	(116)
Other (income) loss, net		**3**	(12)	**4**	(13)
Earnings Before Income Tax		**354**	75	**2,207**	1,304
Income tax expense	*(Note 8)*	**88**	(3)	**729**	223
Net Earnings		**266**	78	**1,478**	1,081
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment		**(25)**	(26)	**48**	71
Comprehensive Income		**241**	52	**1,526**	1,152
Net Earnings per Common Share	*(Note 22)*				
Basic		**0.35**	0.10	**1.96**	1.44
Diluted		**0.35**	0.10	**1.95**	1.43

[1] Refer to Note 24 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at ($ millions)		**December 31, 2011**	December 31, 2010 (1)	January 1, 2010 (1)
Assets				
Current Assets				
Cash and cash equivalents		**495**	300	155
Accounts receivable and accrued revenues		**1,405**	1,059	982
Income tax receivable		**-**	31	40
Current portion of Partnership Contribution Receivable	*(Note 10)*	**372**	346	345
Inventories	*(Note 11)*	**1,291**	880	875
Risk management	*(Note 21)*	**232**	163	60
Assets held for sale	*(Note 9)*	**116**	65	-
Current Assets		**3,911**	2,844	2,457
Exploration and Evaluation Assets	*(Notes 1,12)*	**880**	713	580
Property, Plant and Equipment, net	*(Notes 1,13)*	**14,324**	12,627	12,049
Partnership Contribution Receivable	*(Note 10)*	**1,822**	2,145	2,621
Risk Management	*(Note 21)*	**52**	43	1
Income Tax Receivable		**29**	-	-
Other Assets	*(Note 15)*	**44**	281	192
Deferred Income Taxes		**-**	55	3
Goodwill	*(Note 1)*	**1,132**	1,132	1,146
Total Assets		**22,194**	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities		**2,579**	1,843	1,605
Income tax payable		**329**	154	-
Current portion of Partnership Contribution Payable	*(Note 10)*	**372**	343	340
Risk management	*(Note 21)*	**54**	163	70
Liabilities related to assets held for sale	*(Note 9)*	**54**	7	-
Current Liabilities		**3,388**	2,510	2,015
Long-Term Debt	*(Note 16)*	**3,527**	3,432	3,656
Partnership Contribution Payable	*(Note 10)*	**1,853**	2,176	2,650
Risk Management	*(Note 21)*	**14**	10	4
Decommissioning Liabilities	*(Note 17)*	**1,777**	1,399	1,185
Other Liabilities	*(Note 18)*	**128**	346	246
Deferred Income Taxes		**2,101**	1,572	1,484
Total Liabilities		**12,788**	11,445	11,240
Shareholders' Equity		**9,406**	8,395	7,809
Total Liabilities and Shareholders' Equity		**22,194**	19,840	19,049

(1) Refer to Note 24 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(unaudited)

($ millions)	Share Capital *(Note 19)*	Paid in Surplus	Retained Earnings	AOCI [2]	Total
Balance as at January 1, 2010 [1]	3,681	4,083	45	-	7,809
Net earnings	-	-	1,081	-	1,081
Other comprehensive income (loss)	-	-	-	71	71
Common shares issued under option plans	35	-	-	-	35
Dividends on common shares	-	-	(601)	-	(601)
Balance as at December 31, 2010 [1]	3,716	4,083	525	71	8,395
Net earnings	-	-	1,478	-	1,478
Other comprehensive income (loss)	-	-	-	48	48
Common shares issued under option plans	64	-	-	-	64
Stock-based compensation expense	-	24	-	-	24
Dividends on common shares	-	-	(603)	-	(603)
Balance as at December 31, 2011	**3,780**	**4,107**	**1,400**	**119**	**9,406**

[1] Refer to Note 24 for the impact of adopting IFRS effective January 1, 2010.
[2] Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended December 31,		Three Months Ended		Twelve Months Ended	
($ millions)		**2011**	2010 [1]	**2011**	2010 [1]
Operating Activities					
Net earnings		**266**	78	**1,478**	1,081
Depreciation, depletion and amortization		**383**	324	**1,295**	1,302
Deferred income taxes	*(Note 8)*	**24**	(25)	**575**	141
Cash tax on divestiture of assets		**13**	-	**13**	-
Unrealized (gain) loss on risk management	*(Note 21)*	**242**	275	**(180)**	(46)
Unrealized foreign exchange (gain) loss	*(Note 7)*	**(43)**	(30)	**(42)**	(69)
(Gain) loss on divestiture of assets	*(Note 14)*	**(104)**	3	**(107)**	(116)
Unwinding of discount on decommissioning liabilities	*(Notes 5,17)*	**19**	17	**75**	75
Other		**51**	3	**169**	44
		851	645	**3,276**	2,412
Net change in other assets and liabilities		**(20)**	(14)	**(82)**	(55)
Net change in non-cash working capital		**121**	24	**79**	234
Cash From Operating Activities		**952**	655	**3,273**	2,591
Investing Activities					
Capital expenditures – exploration and evaluation assets	*(Note 12)*	**(186)**	(159)	**(527)**	(350)
Capital expenditures – property, plant and equipment	*(Note 13)*	**(767)**	(590)	**(2,265)**	(1,851)
Proceeds from divestiture of assets		**165**	(3)	**173**	309
Cash tax on divestiture of assets		**(13)**	-	**(13)**	-
Net change in investments and other		**(7)**	1	**(28)**	4
Net change in non-cash working capital		**137**	97	**130**	95
Cash (Used in) Investing Activities		**(671)**	(654)	**(2,530)**	(1,793)
Net Cash Provided (Used) before Financing Activities		**281**	1	**743**	798
Financing Activities					
Net issuance (repayment) of short-term borrowings		**(6)**	(22)	**(9)**	-
Net issuance (repayment) of revolving long-term debt		**-**	-	**-**	(58)
Proceeds on issuance of common shares		**4**	17	**48**	28
Dividends paid on common shares	*(Note 22)*	**(151)**	(151)	**(603)**	(601)
Other		**9**	-	**6**	-
Cash From (Used in) Financing Activities		**(144)**	(156)	**(558)**	(631)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**-**	(9)	**10**	(22)
Increase (Decrease) in Cash and Cash Equivalents		**137**	(164)	**195**	145
Cash and Cash Equivalents, Beginning of Period		**358**	464	**300**	155
Cash and Cash Equivalents, End of Period		**495**	300	**495**	300

[1] Refer to Note 24 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. and its subsidiaries (together "Cenovus" or the "Company") are in the business of the development, production and marketing of crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States ("U.S.").

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at #4000, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. Information on the Company's basis of presentation for these financial statements is found in Note 2.

The Company's reportable segments are as follows:

- **Oil Sands,** which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

- **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.

- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location. Capital expenditures are summarized at the end of the note.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations (For the Three Months Ended December 31)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**951**	678	**611**	515	**2,927**	2,310
Less: Royalties	**94**	73	**57**	35	**-**	-
Revenues	**857**	605	**554**	480	**2,927**	2,310
Expenses						
Purchased product	**-**	-	**-**	-	**2,540**	2,071
Transportation and blending	**362**	241	**34**	29	**-**	-
Operating	**117**	90	**137**	106	**132**	112
Production and mineral taxes	**-**	-	**9**	8	**-**	-
(Gain) loss on risk management	**21**	1	**(50)**	(80)	**17**	2
Operating Cash Flow	**357**	273	**424**	417	**238**	125
Depreciation, depletion and amortization	**93**	94	**203**	187	**76**	35
Exploration expense	**-**	3	**-**	-	**-**	-
Segment Income (Loss)	**264**	176	**221**	230	**162**	90

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(9)**	(32)	**4,480**	3,471
Less: Royalties	**-**	-	**151**	108
Revenues	**(9)**	(32)	**4,329**	3,363
Expenses				
Purchased product	**(9)**	(31)	**2,531**	2,040
Transportation and blending	**-**	-	**396**	270
Operating	**-**	(1)	**386**	307
Production and mineral taxes	**-**	-	**9**	8
(Gain) loss on risk management	**242**	275	**230**	198
	(242)	(275)	**777**	540
Depreciation, depletion and amortization	**11**	8	**383**	324
Exploration expense	**-**	-	**-**	3
Segment Income (Loss)	**(253)**	(283)	**394**	213
General and administrative	**89**	89	**89**	89
Finance costs	**112**	120	**112**	120
Interest income	**(30)**	(34)	**(30)**	(34)
Foreign exchange (gain) loss, net	**(30)**	(28)	**(30)**	(28)
(Gain) loss on divestiture of assets	**(104)**	3	**(104)**	3
Other (income) loss, net	**3**	(12)	**3**	(12)
	40	138	**40**	138
Earnings Before Income Tax			**354**	75
Income tax expense			**88**	(3)
Net Earnings			**266**	78

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Financial Results by Upstream Product (For the Three Months Ended December 31)

Crude Oil and NGLs	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**931**	655	**416**	299	**1,347**	954
Less: Royalties	**93**	78	**54**	32	**147**	110
Revenues	**838**	577	**362**	267	**1,200**	844
Expenses						
Transportation and blending	**361**	241	**26**	19	**387**	260
Operating	**108**	83	**69**	48	**177**	131
Production and mineral taxes	**-**	-	**8**	6	**8**	6
(Gain) loss on risk management	**26**	9	**13**	6	**39**	15
Operating Cash Flow	**343**	244	**246**	188	**589**	432

Natural Gas	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**16**	19	**192**	213	**208**	232
Less: Royalties	**1**	(5)	**3**	3	**4**	(2)
Revenues	**15**	24	**189**	210	**204**	234
Expenses						
Transportation and blending	**1**	-	**8**	10	**9**	10
Operating	**7**	6	**67**	58	**74**	64
Production and mineral taxes	**-**	-	**1**	2	**1**	2
(Gain) loss on risk management	**(5)**	(8)	**(63)**	(86)	**(68)**	(94)
Operating Cash Flow	**12**	26	**176**	226	**188**	252

Other	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**4**	4	**3**	3	**7**	7
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**4**	4	**3**	3	**7**	7
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**2**	1	**1**	-	**3**	1
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**2**	3	**2**	3	**4**	6

Total	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**951**	678	**611**	515	**1,562**	1,193
Less: Royalties	**94**	73	**57**	35	**151**	108
Revenues	**857**	605	**554**	480	**1,411**	1,085
Expenses						
Transportation and blending	**362**	241	**34**	29	**396**	270
Operating	**117**	90	**137**	106	**254**	196
Production and mineral taxes	**-**	-	**9**	8	**9**	8
(Gain) loss on risk management	**21**	1	**(50)**	(80)	**(29)**	(79)
Operating Cash Flow	**357**	273	**424**	417	**781**	690

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations (For the Twelve Months Ended December 31)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**3,291**	2,702	**2,328**	2,284	**10,625**	8,228
Less: Royalties	**284**	279	**205**	170	**-**	-
Revenues	**3,007**	2,423	**2,123**	2,114	**10,625**	8,228
Expenses						
Purchased product	**-**	-	**-**	-	**9,149**	7,674
Transportation and blending	**1,231**	935	**138**	130	**-**	-
Operating	**438**	367	**488**	434	**481**	488
Production and mineral taxes	**-**	-	**36**	34	**-**	-
(Gain) loss on risk management	**70**	(10)	**(152)**	(258)	**14**	(10)
Operating Cash Flow	**1,268**	1,131	**1,613**	1,774	**981**	76
Depreciation, depletion and amortization	**347**	375	**778**	799	**130**	96
Exploration expense	**-**	3	**-**	-	**-**	-
Segment Income (Loss)	**921**	753	**835**	975	**851**	(20)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(59)**	(124)	**16,185**	13,090
Less: Royalties	**-**	-	**489**	449
Revenues	**(59)**	(124)	**15,696**	12,641
Expenses				
Purchased product	**(59)**	(123)	**9,090**	7,551
Transportation and blending	**-**	-	**1,369**	1,065
Operating	**(1)**	(3)	**1,406**	1,286
Production and mineral taxes	**-**	-	**36**	34
(Gain) loss on risk management	**(180)**	(46)	**(248)**	(324)
	181	48	**4,043**	3,029
Depreciation, depletion and amortization	**40**	32	**1,295**	1,302
Exploration expense	**-**	-	**-**	3
Segment Income (Loss)	**141**	16	**2,748**	1,724
General and administrative	**295**	246	**295**	246
Finance costs	**447**	498	**447**	498
Interest income	**(124)**	(144)	**(124)**	(144)
Foreign exchange (gain) loss, net	**26**	(51)	**26**	(51)
(Gain) loss on divestiture of assets	**(107)**	(116)	**(107)**	(116)
Other (income) loss, net	**4**	(13)	**4**	(13)
	541	420	**541**	420
Earnings Before Income Tax			**2,207**	1,304
Income tax expense			**729**	223
Net Earnings			**1,478**	1,081

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Financial Results by Upstream Product (For the Twelve Months Ended December 31)

Crude Oil and NGLs	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**3,217**	2,610	**1,492**	1,229	**4,709**	3,839
Less: Royalties	**282**	276	**193**	153	**475**	429
Revenues	**2,935**	2,334	**1,299**	1,076	**4,234**	3,410
Expenses						
Transportation and blending	**1,229**	934	**104**	86	**1,333**	1,020
Operating	**409**	339	**244**	199	**653**	538
Production and mineral taxes	**-**	-	**27**	28	**27**	28
(Gain) loss on risk management	**87**	14	**43**	5	**130**	19
Operating Cash Flow	**1,210**	1,047	**881**	758	**2,091**	1,805

Natural Gas	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**63**	78	**825**	1,042	**888**	1,120
Less: Royalties	**2**	1	**12**	17	**14**	18
Revenues	**61**	77	**813**	1,025	**874**	1,102
Expenses						
Transportation and blending	**2**	1	**34**	44	**36**	45
Operating	**24**	23	**240**	231	**264**	254
Production and mineral taxes	**-**	-	**9**	6	**9**	6
(Gain) loss on risk management	**(17)**	(24)	**(195)**	(263)	**(212)**	(287)
Operating Cash Flow	**52**	77	**725**	1,007	**777**	1,084

Other	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**11**	14	**11**	13	**22**	27
Less: Royalties	**-**	2	**-**	-	**-**	2
Revenues	**11**	12	**11**	13	**22**	25
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**5**	5	**4**	4	**9**	9
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**6**	7	**7**	9	**13**	16

Total	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**3,291**	2,702	**2,328**	2,284	**5,619**	4,986
Less: Royalties	**284**	279	**205**	170	**489**	449
Revenues	**3,007**	2,423	**2,123**	2,114	**5,130**	4,537
Expenses						
Transportation and blending	**1,231**	935	**138**	130	**1,369**	1,065
Operating	**438**	367	**488**	434	**926**	801
Production and mineral taxes	**-**	-	**36**	34	**36**	34
(Gain) loss on risk management	**70**	(10)	**(152)**	(258)	**(82)**	(268)
Operating Cash Flow	**1,268**	1,131	**1,613**	1,774	**2,881**	2,905

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Geographic Information

The Refining and Marketing segment operates in both Canada and the U.S. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third party purchases and sales of product, is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business.

(For the Three Months Ended December 31)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**548**	398	**2,379**	1,912	**2,927**	2,310
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**548**	398	**2,379**	1,912	**2,927**	2,310
Expenses						
Purchased product	**546**	393	**1,994**	1,678	**2,540**	2,071
Operating	**5**	6	**127**	106	**132**	112
(Gain) loss on risk management	**-**	3	**17**	(1)	**17**	2
Operating Cash Flow	**(3)**	(4)	**241**	129	**238**	125
Depreciation, depletion and amortization	**-**	2	**76**	33	**76**	35
Segment Income (Loss)	**(3)**	(6)	**165**	96	**162**	90

(For the Twelve Months Ended December 31)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1,953**	1,604	**8,672**	6,624	**10,625**	8,228
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**1,953**	1,604	**8,672**	6,624	**10,625**	8,228
Expenses						
Purchased product	**1,926**	1,579	**7,223**	6,095	**9,149**	7,674
Operating	**22**	16	**459**	472	**481**	488
(Gain) loss on risk management	**-**	-	**14**	(10)	**14**	(10)
Operating Cash Flow	**5**	9	**976**	67	**981**	76
Depreciation, depletion and amortization	**-**	10	**130**	86	**130**	96
Segment Income (Loss)	**5**	(1)	**846**	(19)	**851**	(20)

Capital Expenditures

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Capital				
Oil Sands	**465**	304	**1,415**	857
Conventional	**330**	220	**788**	526
Refining and Marketing	**73**	139	**393**	656
Corporate	**35**	38	**127**	76
	903	701	**2,723**	2,115
Acquisition Capital				
Oil Sands	**40**	3	**44**	23
Conventional	**10**	7	**25**	25
Refining and Marketing	**-**	38	**-**	38
Corporate	**(1)**	-	**2**	-
Total	**952**	749	**2,794**	2,201

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

By Segment

	Exploration and Evaluation Assets			Property, Plant and Equipment		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**741**	570	452	**6,224**	5,219	4,870
Conventional	**139**	143	128	**4,668**	4,409	4,645
Refining and Marketing	**-**	-	-	**3,200**	2,853	2,418
Corporate and Eliminations	**-**	-	-	**232**	146	116
Consolidated	**880**	713	580	**14,324**	12,627	12,049

	Goodwill			Total Assets		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**10,524**	9,487	9,426
Conventional	**393**	393	407	**5,566**	5,186	5,453
Refining and Marketing	**-**	-	-	**4,927**	4,282	3,669
Corporate and Eliminations	**-**	-	-	**1,177**	885	501
Consolidated	**1,132**	1,132	1,146	**22,194**	19,840	19,049

By Geographic Region

	Exploration and Evaluation Assets			Property, Plant and Equipment		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Canada	**880**	713	580	**11,124**	9,774	9,645
United States	**-**	-	-	**3,200**	2,853	2,404
Consolidated	**880**	713	580	**14,324**	12,627	12,049

	Goodwill			Total Assets		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Canada	**1,132**	1,132	1,146	**17,536**	15,906	15,669
United States	**-**	-	-	**4,658**	3,934	3,380
Consolidated	**1,132**	1,132	1,146	**22,194**	19,840	19,049

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

The interim Consolidated Financial Statements of Cenovus have been prepared using the historical cost convention except for the revaluation of certain non-current assets and financial instruments. These Financial Statements have been prepared in accordance with International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34") and International Financial Reporting Standard 1, "*First-time Adoption of International Financial Reporting Standards*" ("IFRS 1") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

The preparation of these interim Consolidated Financial Statements resulted in changes to the Company's accounting policies as presented in the Consolidated Financial Statements for the year ended December 31, 2010 prepared under Canadian generally accepted accounting principles ("previous GAAP"). The Company's accounting policies have been applied consistently to all years presented in these interim Consolidated Financial Statements with the exception of certain IFRS 1 exemptions the Company applied in its transition from previous GAAP to International Financial Reporting Standards ("IFRS") as discussed in Note 24. These Consolidated Financial Statements include all necessary disclosures required for interim financial statements but do not include all of the necessary disclosures required for annual financial statements. Therefore, these interim Consolidated Financial Statements should be read in conjunction with the Cenovus annual audited Consolidated Financial Statements and

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE (continued)

the notes thereto for the year ended December 31, 2010 and the annual disclosures and accounting policies included in the interim Consolidated Financial Statements as at and for the three months ended March 31, 2011.

These interim Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Audit Committee effective February 14, 2012.

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2011.

3. RECENT ACCOUNTING PRONOUNCEMENTS

Joint Arrangements and Off Balance Sheet Activities

In May 2011, the IASB issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.

- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts for the arrangement as an investment using the equity method.

- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the five standards are adopted concurrently. The Company is currently evaluating the impact of adopting these standards on its Consolidated Financial Statements.

Employee Benefits

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates and the valuation of plan assets, will be recognized in OCI. Furthermore, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Early adoption is permitted. The Company is currently evaluating the impact of adopting these amendments on its Consolidated Financial Statements.

3. RECENT ACCOUNTING PRONOUNCEMENTS (continued)

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 13 on its Consolidated Financial Statements.

Financial Instruments

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. The Company is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The Company is currently evaluating the impact of adopting this amendment on its Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures*" ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar arrangements.
- IAS 32, "*Financial Instruments: Presentation*" ("IAS 32") has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. The Company is currently evaluating the impact of adopting the amendments to IFRS 7 and IAS 32 on its Consolidated Financial Statements.

4. INTERESTS IN JOINT OPERATIONS

Cenovus has a 50 percent interest in FCCL Partnership, a jointly controlled entity which is involved in the development and production of crude oil. In addition, through its interest in the general partner and a limited partner, Cenovus has a 50 percent interest in WRB Refining LP, a jointly controlled entity, which owns two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products.

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing Segments, respectively. Summarized financial statement information for these jointly controlled entities is as follows:

	FCCL Partnership [1]		WRB Refining LP [1]	
Consolidated Statements of Earnings For the three months ended December 31,	**2011**	2010	**2011**	2010
Revenues	**702**	467	**2,379**	1,912
Expenses				
Purchased product	**-**	-	**1,994**	1,678
Operating, Transportation and blending and Realized gain/loss on risk management	**406**	276	**144**	105
Operating Cash Flow	**296**	191	**241**	129
Depreciation, depletion and amortization	**60**	55	**76**	33
Other expenses (income)	**43**	70	**10**	7
Net Earnings (Loss)	**193**	66	**155**	89

[1] FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.

	FCCL Partnership		WRB Refining LP	
Consolidated Statements of Earnings For the twelve months ended December 31,	**2011**	2010	**2011**	2010
Revenues	**2,364**	1,829	**8,672**	6,624
Expenses				
Purchased product	**-**	-	**7,223**	6,095
Operating, Transportation and blending and Realized gain/loss on risk management	**1,397**	1,074	**473**	462
Operating Cash Flow	**967**	755	**976**	67
Depreciation, depletion and amortization	**205**	210	**130**	86
Other expenses (income)	**(136)**	20	**(4)**	13
Net Earnings (Loss)	**898**	525	**850**	(32)

Consolidated Balance Sheets	FCCL Partnership		WRB Refining LP	
As at	**December 31, 2011**	December 31, 2010	**December 31, 2011**	December 31, 2010
Current Assets	**937**	703	**1,402**	951
Long-term Assets	**6,864**	6,419	**3,188**	2,840
Current Liabilities	**317**	229	**759**	559
Long-term Liabilities	**83**	40	**73**	327

5. FINANCE COSTS

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Interest Expense–Short-Term Borrowings and Long-Term Debt	**53**	54	**213**	227
Interest Expense–Partnership Contribution Payable	**34**	39	**138**	165
Unwinding of Discount on Decommissioning Liabilities	**19**	17	**75**	75
Other	**6**	10	**21**	31
	112	120	**447**	498

6. INTEREST INCOME

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Interest Income–Partnership Contribution Receivable	**29**	34	**120**	144
Other	**1**	-	**4**	-
	30	34	**124**	144

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	**(77)**	(123)	**78**	(182)
U.S. dollar Partnership Contribution Receivable issued from Canada	**37**	77	**(107)**	91
Other	**(3)**	16	**(13)**	22
Unrealized Foreign Exchange (Gain) Loss	**(43)**	(30)	**(42)**	(69)
Realized Foreign Exchange (Gain) Loss	**13**	2	**68**	18
	(30)	(28)	**26**	(51)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Current Tax				
Canada	**62**	22	**150**	82
United States	**2**	-	**4**	-
Total Current Tax	**64**	22	**154**	82
Deferred Tax	**24**	(25)	**575**	141
	88	(3)	**729**	223

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

For the year ended December 31,	**2011**	2010
Earnings Before Income Tax	**2,207**	1,304
Canadian Statutory Rate	**26.7%**	28.2%
Expected Income Tax	**589**	368
Effect of Taxes Resulting from:		
Foreign tax rate differential	**78**	(22)
Non-deductible stock-based compensation	**18**	34
Multi-jurisdictional financing	**(50)**	(93)
Foreign exchange gains (losses) not included in net earnings	**(9)**	28
Non-taxable capital (gains) losses	**(9)**	(13)
Capital losses	**26**	(107)
Adjustments arising from prior year tax filings	**31**	26
Other	**55**	2
	729	223
Effective Tax Rate	**33.0%**	17.1%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

9. ASSETS AND LIABILITIES HELD FOR SALE

Assets and liabilities classified as held for sale consisted of the following:

As at	December 31, 2011	December 31, 2010
Assets Held for Sale		
Property, plant and equipment	**116**	65
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	**54**	5
Deferred income taxes	**-**	2
	54	7

Non-Core Natural Gas Assets

At December 31, 2011, the Company classified certain non-core natural gas assets located in Northern Alberta as assets held for sale. The assets were recorded at the lesser of fair value less costs to sell and their carrying amount, resulting in an impairment loss of approximately $2 million which has been recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income. These assets and the related liabilities are reported in the Conventional segment.

In January 2012, the Company completed the sale of the natural gas assets to an unrelated third party for net proceeds of $63 million.

Marine Terminal Facilities

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million. The net assets were recorded at estimated fair value less costs to sell and classified as held for sale. These assets and liabilities were reported in the Refining and Marketing segment. Cenovus recognized a bargain purchase gain of $12 million, resulting from the excess fair value of the net assets acquired over the cash consideration paid. The gain was recorded in other income.

In October 2011, the Company completed the sale of the marine terminal facilities and recorded an after-tax gain on sale of $89 million.

10. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

The following tables represent Cenovus's 50 percent share of amounts receivable and payable in relation to the creation and activities of the joint operations with ConocoPhillips (Note 4). Both notes are denominated in U.S. dollars.

Partnership Contribution Receivable

As at	December 31, 2011	December 31, 2010
Current	**372**	346
Long-term	**1,822**	2,145
	2,194	2,491

Partnership Contribution Payable

As at	December 31, 2011	December 31, 2010
Current	**372**	343
Long-term	**1,853**	2,176
	2,225	2,519

10. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE (continued)

At December 31, 2010, in addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities included equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements (Notes 15 and 18). These amounts were fully repaid as at December 31, 2011.

11. INVENTORIES

As at	**December 31, 2011**	December 31, 2010
Product		
Refining and Marketing	**1,079**	779
Oil Sands	**186**	80
Conventional	**1**	-
Parts and Supplies	**25**	21
	1,291	880

12. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 13)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
As at December 31, 2010	713
Additions	527
Transfers to property, plant and equipment (Note 13)	(356)
Divestitures	(3)
Change in decommissioning liabilities	(1)
As at December 31, 2011	**880**

Exploration and evaluation assets ("E&E assets") consist of the Company's evaluation projects which are pending the determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the twelve months ended December 31, 2011 include $15 million of internal costs directly related to the evaluation of these projects (twelve months ended December 31, 2010–$11 million).

For the twelve months ended December 31, 2011, $356 million of E&E assets were transferred to property, plant and equipment – development and production assets following the determination of technical feasibility and commercial viability of the projects in question (twelve months ended December 31, 2010–$144 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. There were no impairments of E&E assets in 2011 and 2010.

13. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets Development & Production	Upstream Assets Other Upstream	Refining Equipment	Other *	Total
COST					
As at January 1, 2010	20,836	134	2,419	427	23,816
Additions	1,061	19	651	136	1,867
Transfers from E&E assets (Note 12)	144	-	-	-	144
Transfers and reclassifications	-	-	-	(92)	(92)
Change in decommissioning liabilities	237	-	22	-	259
Exchange rate movements	(2)	-	(142)	-	(144)
Divestitures	(556)	-	-	(21)	(577)
As at December 31, 2010	21,720	153	2,950	450	25,273
Additions	1,704	41	391	131	2,267
Transfers from E&E assets (Note 12)	356	-	-	-	356
Transfers and reclassifications	(326)	-	(5)	(2)	(333)
Change in decommissioning liabilities	403	-	10	1	414
Exchange rate movements	1	-	79	-	80
Divestitures (Note 14)	-	-	-	(4)	(4)
As at December 31, 2011	**23,858**	**194**	**3,425**	**576**	**28,053**
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT					
As at January 1, 2010	11,342	113	15	297	11,767
Depreciation and depletion expense	1,163	11	72	42	1,288
Transfers and reclassifications	-	-	-	(28)	(28)
Impairment losses	-	-	14	-	14
Exchange rate movements	(1)	-	(4)	-	(5)
Divestitures	(383)	-	-	(7)	(390)
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	1,108	15	85	40	1,248
Impairment losses	2	-	45	-	47
Transfers and reclassifications	(211)	-	(5)	-	(216)
Exchange rate movements	1	-	3	-	4
As at December 31, 2011	**13,021**	**139**	**225**	**344**	**13,729**
CARRYING VALUE					
As at January 1, 2010	9,494	21	2,404	130	12,049
As at December 31, 2010	9,599	29	2,853	146	12,627
As at December 31, 2011	**10,837**	**55**	**3,200**	**232**	**14,324**

* Includes office furniture, fixtures, leasehold improvements, information technology, aircraft and marine terminal facilities.

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of $125 million for the twelve months ended December 31, 2011 (for the twelve months ended December 31, 2010–$87 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized in 2011 (2010–$nil).

Capital inventory, which is included in development and production assets, is not subject to depreciation until it is put in use and totaled $52 million at December 31, 2011 (December 31, 2010–$42 million).

Refining expenditures capitalized during the construction phase are not subject to depreciation until put in use and totaled $125 million at December 31, 2011 (December 31, 2010–$1,673 million).

As at December 31, 2011, other property, plant and equipment included $112 million of costs not subject to depreciation until the related assets are put in use (December 31, 2010–$45 million).

Impairment

The impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income.

13. PROPERTY, PLANT AND EQUIPMENT, NET (continued)

Depreciation, depletion and amortization expense includes impairment losses as follows:

As at	**December 31, 2011**	December 31, 2010
Development and Production	**2**	-
Refining Equipment	**45**	14
	47	14

The impairment losses during the year were related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations and an impairment on non-core natural gas assets that have been reclassified as held for sale (Note 9). The natural gas assets reside in the Conventional segment. The 2010 impairment loss was related to a processing unit at the Borger Refinery which was determined to be a redundant asset.

14. DIVESTITURES

In 2011, the Company disposed of non-core oil and gas properties and marine terminal facilities recognizing an after-tax gain of $91 million in the Statement of Earnings and Comprehensive Income. In 2010, an after-tax gain of $116 million was recognized on the disposition of non-core oil and gas properties and corporate assets.

15. OTHER ASSETS

As at	**December 31, 2011**	December 31, 2010
Partner Loans	**-**	274
Long-term Receivables	**18**	7
Prepaids	**8**	-
Other	**18**	-
	44	281

16. LONG-TERM DEBT

As at	**December 31, 2011**	December 31, 2010
Canadian Dollar Denominated Debt		
Revolving term debt *	**-**	-
U.S. Dollar Denominated Debt		
Revolving term debt *	**-**	-
Unsecured notes (US$ 3,500)	**3,559**	3,481
	3,559	3,481
Total Debt Principal	**3,559**	3,481
Debt Discounts and Transaction Costs	**(32)**	(49)
Current Portion of Long-Term Debt	**-**	-
	3,527	3,432

* Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

At December 31, 2011, the Company is in compliance with all of the terms of its debt agreements.

17. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the future costs associated with the retirement of upstream oil and gas assets and refining facilities. The aggregate carrying amount of the obligation is as follows:

As at	**December 31, 2011**	December 31, 2010
Decommissioning Liabilities, Beginning of Year	**1,399**	1,185
Liabilities Incurred	**49**	44
Liabilities Settled	**(56)**	(32)
Liabilities Divested	**-**	(90)
Transfers and Reclassifications	**(55)**	(5)
Change in Estimated Future Cash Flows	**146**	51
Change in Discount Rate	**218**	173
Unwinding of Discount on Decommissioning Liabilities	**75**	75
Foreign Currency Translation	**1**	(2)
Decommissioning Liabilities, End of Year	**1,777**	1,399

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.8 percent as at December 31, 2011 (December 31, 2010–5.4 percent).

18. OTHER LIABILITIES

As at	**December 31, 2011**	December 31, 2010
Partner Loans	**-**	274
Deferred Revenue	**35**	37
Employee Long-Term Incentives	**55**	18
Pension and Other Post-Employment Benefits	**16**	13
Other	**22**	4
	128	346

19. SHARE CAPITAL

Authorized

Cenovus 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. The First and Second Preferred Shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

Issued and Outstanding

As at	**December 31, 2011**		December 31, 2010	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**752,675**	**3,716**	751,309	3,681
Common Shares Issued under Stock Option Plans	**1,824**	**64**	1,366	35
Outstanding, End of Year	**754,499**	**3,780**	752,675	3,716

At December 31, 2011, there were 30 million (December 31, 2010–26 million) common shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at December 31, 2011.

19. SHARE CAPITAL (continued)

Stock-Based Compensation

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option 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 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("Performance TSARs"). The Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and have an additional vesting requirement whereby vesting is subject to achievement of prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited.

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's Common Share price relative to that of Encana's Common Share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus Replacement TSARs are measured against the Cenovus Common Share price while Encana Replacement TSARs are measured against the Encana Common Share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

NSRs

The weighted average unit fair value of NSRs granted during the twelve months ended December 31, 2011 was $8.27 before considering forfeitures. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**2.46%**
Expected Dividend Yield	**2.16%**
Expected Volatility (1)	**28.81%**
Expected Life (Years)	**4.55**

(1) Expected volatility has been based on historical volatility of the Company's publicly traded shares.

19. SHARE CAPITAL (continued)

The following tables summarize the information related to the NSRs as at December 31, 2011:

As at December 31, 2011 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	-	-
Granted	5,931	36.96
Exercised as options for common shares	-	-
Forfeited	(122)	37.50
Outstanding, End of Year	5,809	36.95
Exercisable, End of Year	1	37.54

(thousands of units)	Outstanding NSRs			Exercisable NSRs	
Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	5,809	6.24	36.95	1	37.54
	5,809	6.24	36.95	1	37.54

TSARs Held by Cenovus Employees

The Company has recorded a liability of $90 million at December 31, 2011 (December 31, 2010–$87 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	1.10%
Expected Dividend Yield	2.36%
Expected Volatility [1]	31.95%
Cenovus's Common Share Price	$33.83

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2011 was $43 million (December 31, 2010–$42 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,044	7,073	19,117	27.75
Granted	138	-	138	33.40
Exercised for cash payment	(1,274)	(641)	(1,915)	26.31
Exercised as options for common shares	(1,202)	(564)	(1,766)	26.38
Forfeited	(315)	(338)	(653)	28.37
Outstanding, End of Year	9,391	5,530	14,921	28.12
Exercisable, End of Year	4,618	4,256	8,874	29.15

The weighted average market price of Cenovus's common shares at the date of exercise during the twelve months ended December 31, 2011 was $35.71.

19. SHARE CAPITAL (continued)

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	7,617	3,578	11,195	3.32	26.43	3,029	2,304	5,333	26.45
30.00 to 39.99	1,711	1,952	3,663	1.40	33.03	1,526	1,952	3,478	33.04
40.00 to 49.99	63	-	63	1.45	43.30	63	-	63	43.30
	9,391	5,530	14,921	2.84	28.12	4,618	4,256	8,874	29.15

The market price of Cenovus common shares at December 31, 2011 was $33.83.

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana Replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of $1 million at December 31, 2011 (December 31, 2010–$24 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	0.99%
Expected Dividend Yield	4.31%
Expected Volatility [1]	28.04%
Encana's Common Share Price	$18.89

[1] Expected volatility has been based on historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at December 31, 2011 was $nil (December 31, 2010–$6 million).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	6,429	7,098	13,527	31.17
Exercised for cash payment	(1,824)	(451)	(2,275)	26.97
Exercised as options for Encana common shares	(16)	-	(16)	25.71
Forfeited	(308)	(517)	(825)	32.72
Outstanding, End of Year	4,281	6,130	10,411	31.97
Exercisable, End of Year	3,605	4,856	8,461	32.64

The weighted average market price of Encana's common shares at the date of exercise during the twelve months ended December 31, 2011 was $31.95.

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	2,437	4,014	6,451	1.48	29.15	1,778	2,740	4,518	29.20
30.00 to 39.99	1,711	2,116	3,827	1.12	36.26	1,694	2,116	3,810	36.28
40.00 to 49.99	131	-	131	1.48	44.86	131	-	131	44.86
50.00 to 59.99	2	-	2	1.39	50.39	2	-	2	50.39
	4,281	6,130	10,411	1.35	31.97	3,605	4,856	8,461	32.64

The market price of Encana common shares at December 31, 2011 was $18.89.

19. SHARE CAPITAL (continued)

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's employees when these employees exercise a Cenovus Replacement TSAR for cash. No compensation expense is recognized and no further Cenovus Replacement TSARs will be granted to Encana employees.

The Company has recorded a liability of $83 million at December 31, 2011 (December 31, 2010–$123 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**0.99%**
Expected Dividend Yield	**2.36%**
Expected Volatility (1)	**31.95%**
Cenovus's Common Share Price	**$33.83**

(1) Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at December 31, 2011 was $32 million (December 31, 2010–$60 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**8,214**	**8,940**	**17,154**	**28.16**
Exercised for cash payment	**(4,082)**	**(2,758)**	**(6,840)**	**27.00**
Exercised as options for common shares	**(55)**	**(3)**	**(58)**	**23.29**
Forfeited	**(142)**	**(428)**	**(570)**	**29.14**
Outstanding, End of Year	**3,935**	**5,751**	**9,686**	**28.96**
Exercisable, End of Year	**3,203**	**4,319**	**7,522**	**29.73**

The weighted average market price of Cenovus's common shares at the date of exercise during the twelve months ended December 31, 2011 was $35.80.

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	**2,197**	**3,807**	**6,004**	**1.55**	**26.41**	**1,465**	**2,375**	**3,840**	**26.48**
30.00 to 39.99	**1,671**	**1,944**	**3,615**	**1.11**	**32.95**	**1,671**	**1,944**	**3,615**	**32.95**
40.00 to 49.99	**67**	**-**	**67**	**1.44**	**42.88**	**67**	**-**	**67**	**42.88**
	3,935	**5,751**	**9,686**	**1.38**	**28.96**	**3,203**	**4,319**	**7,522**	**29.73**

The market price of Cenovus common shares at December 31, 2011 was $33.83.

B) Performance Share Units (PSU)

Cenovus has granted Performance Share Units ("PSUs") to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a Common Share of Cenovus or a cash payment equal to the value of a Cenovus Common Share. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $55 million at December 31, 2011 (December 31, 2010–$18 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2011. The intrinsic value of vested PSUs was $nil at December 31, 2011 and 2010 as PSUs are paid out upon vesting.

19. SHARE CAPITAL (continued)

The following table summarizes the information related to the PSUs held by Cenovus employees as at December 31, 2011:

(thousands of units)	PSUs
Outstanding, Beginning of Year	**1,252**
Granted	**1,409**
Cancelled	**(98)**
Units in Lieu of Dividends	**60**
Outstanding, End of Year	**2,623**

C) Deferred Share Units (DSU)

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $35 million at December 31, 2011 (December 31, 2010–$31 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2011. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2011:

(thousands of units)	DSUs
Outstanding, Beginning of Year	**940**
Granted to Directors	**65**
Granted from Annual Bonus Awards	**17**
Units in Lieu of Dividends	**23**
Exercised	**(3)**
Outstanding, End of Year	**1,042**

D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses on the Consolidated Statements of Earnings and Comprehensive Income:

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
NSRs	**5**	-	**16**	-
TSARs held by Cenovus employees	**13**	32	**24**	45
Encana Replacement TSARs held by Cenovus employees	**(1)**	(5)	**(8)**	(20)
PSUs	**8**	5	**27**	13
DSUs	**2**	4	**4**	9
Total stock-based compensation expense (recovery)	**27**	36	**63**	47

20. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt includes the Company's short-term borrowings plus long-term debt, including the current portion. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

20. CAPITAL STRUCTURE (continued)

Cenovus monitors its capital structure financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent (See Note 24 for the impact of IFRS on the Debt to Capitalization ratio).

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Short-Term Borrowings	**-**	-	-
Long-Term Debt	**3,527**	3,432	3,656
Debt	**3,527**	3,432	3,656
Shareholders' Equity	**9,406**	8,395	7,809
Total Capitalization	**12,933**	11,827	11,465
Debt to Capitalization	**27%**	29%	32%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at	**December 31, 2011**	December 31, 2010
Debt	**3,527**	3,432
Net Earnings	**1,478**	1,081
Add (deduct):		
Finance costs	**447**	498
Interest income	**(124)**	(144)
Income tax expense	**729**	223
Depreciation, depletion and amortization	**1,295**	1,302
Exploration expense	**-**	-
Unrealized (gain) loss on risk management	**(180)**	(46)
Foreign exchange (gain) loss, net	**26**	(51)
(Gain) loss on divestiture of assets	**(107)**	(116)
Other (income) loss, net	**4**	(13)
Adjusted EBITDA	**3,568**	2,734
Debt to Adjusted EBITDA	**1.0x**	1.3x

It is Cenovus's intention to maintain investment grade credit ratings to help ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, Cenovus changed its definition of Adjusted EBITDA to exclude unrealized gains and losses on risk management activities. The Adjusted EBITDA and the ratio of Debt to Adjusted EBITDA for prior periods have been re-presented in a consistent manner. As noted above, Cenovus's capital structure objectives and targets remain unchanged from previous periods. At December 31, 2011, Cenovus is in compliance with all of the terms of its debt agreements.

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings, long-term debt and obligations for stock-based compensation carried at fair value. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

A) Fair Value of Financial Assets and Liabilities

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

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable, partner loans and long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based prices sourced from market data. At December 31, 2011, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,527 million and the fair value was $4,316 million (December 31, 2010 carrying value–$3,432 million, fair value–$3,940 million).

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement, the risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

Net Risk Management Position

As at	**December 31, 2011**	December 31, 2010
Risk Management		
Current asset	**232**	163
Long-term asset	**52**	43
	284	206
Risk Management		
Current liability	**54**	163
Long-term liability	**14**	10
	68	173
Net Risk Management Asset (Liability) [1]	**216**	33

[1] Of the $216 million net risk management asset balance at December 31, 2011, a liability of $3 million relates to the contract with Encana (December 31, 2010–net asset of $41 million).

Summary of Unrealized Risk Management Positions

As at	**December 31, 2011**			December 31, 2010		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**22**	**65**	**(43)**	4	159	(155)
Natural Gas	**247**	**3**	**244**	202	-	202
Power	**15**	**-**	**15**	-	14	(14)
Total Fair Value	**284**	**68**	**216**	206	173	33

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	**December 31, 2011**	December 31, 2010
Prices actively quoted	**226**	40
Prices sourced from observable data or market corroboration	**(10)**	(7)
Total Fair Value	**216**	33

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Net Fair Value of Commodity Price Positions at December 31, 2011

As at December 31, 2011	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,800 bbls/d	2012	US$98.72/bbl	**(1)**
WTI NYMEX Fixed Price	24,500 bbls/d	2012	C$99.47/bbl	**(12)**
Other Fixed Price Contracts *		2012-2013		**(22)**
Other Financial Positions **				**(8)**
Crude Oil Fair Value Position				**(43)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**131**
AECO Fixed Price	127 MMcf/d	2012	C$4.50/Mcf	**73**
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	**43**
Other Fixed Price Contracts *		2012-2013		**(3)**
Natural Gas Fair Value Position				**244**
Power Purchase Contracts				
Power Fair Value Position				**15**

* Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada, various sales points and quality differentials.
** Other financial positions are part of ongoing operations to market the Company's production.

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2011**	2010	**2011**	2010
Realized Gain (Loss) [1]				
Crude Oil	**(39)**	(18)	**(135)**	(17)
Natural Gas	**67**	95	**210**	289
Refining	**(17)**	1	**(14)**	10
Power	**1**	(1)	**7**	(4)
	12	77	**68**	278
Unrealized Gain (Loss) [2]				
Crude Oil	**(312)**	(153)	**106**	(92)
Natural Gas	**76**	(115)	**38**	152
Refining	**(9)**	(6)	**7**	(8)
Power	**3**	(1)	**29**	(6)
	(242)	(275)	**180**	46
Gain (Loss) on Risk Management	**(230)**	(198)	**248**	324

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Reconciliation of Unrealized Risk Management Positions from January 1 to December 31,

	2011		2010
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**33**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**248**	**248**	324
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**3**	**-**	-
Fair Value of Contracts Realized During the Year	**(68)**	**(68)**	(278)
Fair Value of Contracts, End of Year	**216**	**180**	46

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax at December 31, 2011 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$10 per bbl applied to WTI hedges	**(214)**	**214**
Crude oil differential price	± US$5 per bbl applied to differential hedges tied to production	**67**	**(67)**
Natural gas commodity price	± $1 per mcf applied to NYMEX and AECO natural gas hedges	**(160)**	**160**
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	**2**	**(2)**
Power commodity price	± $25 per MWHr applied to power hedge	**19**	**(19)**

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. To help protect against widening crude oil price differentials, Cenovus has entered into a limited number of swaps and futures to manage the price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX and AECO prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

Power – The Company has in place a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk 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. Agreements are entered into with major financial institutions with investment grade credit ratings or with counterparties having investment grade credit ratings.

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2011, over 92 percent (December 31, 2010–92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2011, Cenovus had two counterparties whose net settlement position individually accounted for more than 10 percent (December 31, 2010–two counterparties) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value. The current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 20, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its debt shelf prospectuses. At December 31, 2011, Cenovus's committed credit facility was fully available. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1,500 million and a U.S. debt shelf prospectus for US$1,500 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

Undiscounted cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 – 3 Years	4 – 5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,579	-	-	-	**2,579**
Risk Management Liabilities	54	14	-	-	**68**
Long-Term Debt (1)	208	1,230	343	5,182	**6,963**
Partnership Contribution Payable (1)	497	994	994	125	**2,610**
Other (1)	3	10	3	4	**20**

(1) Principal and interest, including current portion.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At December 31, 2011, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million at December 31, 2010) and US$2,157 million related to the U.S. dollar Partnership Contribution Receivable (US$2,505 million at December 31, 2010). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $13 million change in foreign exchange (gain) loss at December 31, 2011 (December 31, 2010–$10 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (December 31, 2010–$nil). This assumes the amount of fixed and floating rate debt remains unchanged from the respective balance sheet dates.

22. SUPPLEMENTARY INFORMATION

A) Net Earnings Per Share

Three Months Ended	December 31, 2011			December 31, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	**266**	**754.4**	**$0.35**	78	752.2	$0.10
Dilutive effect of Cenovus TSARs	**-**	**2.7**		-	2.7	
Dilutive effect of NSRs	**-**	**-**		-	-	
Net earnings per share - diluted	**266**	**757.1**	**$0.35**	78	754.9	$0.10

Twelve Months Ended	December 31, 2011			December 31, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	**1,478**	**754.0**	**$1.96**	1,081	751.9	$1.44
Dilutive effect of Cenovus TSARs	**-**	**3.7**		-	2.1	
Dilutive effect of NSRs	**-**	**-**		-	-	
Net earnings per share - diluted	**1,478**	**757.7**	**$1.95**	1,081	754.0	$1.43

B) Dividends Per Share

The Company paid dividends of $603 million, $0.80 per share, for the twelve months ended December 31, 2011 (December 31, 2010–$601 million, $0.80 per share).

The Cenovus Board of Directors declared a first quarter dividend of $0.22 per share, payable on March 30, 2012, to common shareholders of record as of March 15, 2012.

23. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

24. FIRST TIME ADOPTION OF IFRS

Transition to IFRS

The Company has adopted IFRS effective January 1, 2011. The Company adopted IFRS in accordance with IFRS 1 and has prepared its Consolidated Financial Statements with IFRS applicable for periods beginning on or after January 1, 2010, using the accounting policies referenced in Note 3 of the interim Consolidated Financial Statements for the period ended March 31, 2011. For all periods up to and including the year ended December 31, 2010, the Company prepared its Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). This note explains the principal adjustments made by the Company to restate its previous GAAP Consolidated Financial Statements on transition to IFRS.

Exemptions Applied under IFRS 1

On first-time adoption of IFRS, the general principle is that an entity retrospectively restates its results for all standards in force at the first reporting date. However, IFRS 1 provides certain exemptions from the general requirements of IFRS to assist with the transition process. Cenovus has applied the following exemptions in the preparation of its opening Balance Sheet dated January 1, 2010 (the "Transition Date"):

- **Fair Value as Deemed Cost** – The Company has elected to measure its Refining assets at their fair values at the Transition Date and use those fair values as their deemed cost at that date (see Note A).

24. FIRST TIME ADOPTION OF IFRS (continued)

- **Deemed Cost Election for Oil and Gas Assets** – Under previous GAAP, Cenovus accounted for its oil and gas properties in one cost centre using full cost accounting. The Company has elected to measure its oil and gas properties at the Transition Date on the following basis:

  a) exploration and evaluation assets at the amount determined under the Company's previous GAAP; and
  b) the remainder allocated to the underlying property, plant and equipment assets on a pro rata basis using proved reserve values discounted at 10 percent at the Transition Date (see Note B).

  This basis was used in order to be consistent with the allocation used as part of the Arrangement.

- **Leases** – Cenovus has elected to assess lease arrangements using the facts and circumstances as of the Transition Date under International Financial Reporting Interpretations Committee Interpretation 4, "*Determining whether an Arrangement contains a Lease*" ("IFRIC 4").

- **Employee Benefits** – The Company has elected not to apply IAS 19, "*Employee Benefits*" ("IAS 19") retrospectively and as such all cumulative actuarial gains and losses on the Company's defined benefit plans were recognized at the Transition Date (see Note F).

- **Business Combinations** – IFRS 3, "*Business Combinations*" ("IFRS 3") has not been applied to business combinations that occurred before the Transition Date.

- **Cumulative Currency Translation Differences** – Cumulative currency translation differences for all foreign operations are deemed to be zero at the Transition Date (see Note J).

- **Decommissioning Liabilities** – Cenovus applied the deemed cost election for oil and gas assets under IFRS 1 and as such decommissioning liabilities at the date of transition have been measured in accordance with IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") (see Note D).

- **Borrowing Costs** – In accordance with IFRS 1, the Company has elected to apply IAS 23, "*Borrowing Costs*" ("IAS 23") to qualifying assets for which the commencement date for capitalization of borrowing costs occurred on or after the Transition Date. Borrowing costs have not been capitalized on qualifying assets under construction on or before the Transition Date.

- **Estimates** – Hindsight was not used to create or revise estimates and accordingly, the estimates made by the Company under previous GAAP are consistent with their application under IFRS.

Under IFRS 1, the opening Balance Sheet adjustments are recorded directly to retained earnings, or if appropriate, another category of equity. As Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana into two independent energy companies, Encana and Cenovus, all opening Balance Sheet adjustments have been recorded to paid in surplus. The impacts of applying the above noted IFRS 1 exemptions and the accounting policy differences between previous GAAP and IFRS are summarized in the following tables:

24. FIRST TIME ADOPTION OF IFRS (continued)

Reconciliation of Shareholders' Equity as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's equity reported in accordance with previous GAAP to its equity in accordance with IFRS at the Transition Date:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – December 31, 2009		3,681	5,896	45	(14)	9,608
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	-	-	(2,585)
Oil and gas property, plant and equipment	B	-	-	-	-	-
Deferred asset	C	-	(121)	-	-	(121)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	-	-	(27)
Employee benefits	F	-	(14)	-	-	(14)
Deferred income tax	I	-	986	-	-	986
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
		-	(1,813)	-	14	(1,799)
As reported under IFRS – January 1, 2010		3,681	4,083	45	-	7,809

* Accumulated Other Comprehensive Income (Loss).

The following is a reconciliation of the Company's equity reported in accordance with previous GAAP to its equity in accordance with IFRS at December 31, 2010:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – December 31, 2010		3,716	5,896	437	(27)	10,022
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	126	-	(2,459)
Oil and gas property, plant and equipment	B	-	-	(135)	-	(135)
Deferred asset	C	-	(121)	17	-	(104)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	9	-	(18)
Employee benefits	F	-	(14)	2	-	(12)
Gain (loss) on divestiture of assets	G	-	-	125	-	125
Pre-exploration expense	H	-	-	(3)	-	(3)
Deferred income tax	I	-	986	(53)	-	933
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
Period foreign currency translation adjustments	J	-	-	-	84	84
		-	(1,813)	88	98	(1,627)
As reported under IFRS – December 31, 2010		3,716	4,083	525	71	8,395

* Accumulated Other Comprehensive Income (Loss).

24. FIRST TIME ADOPTION OF IFRS (continued)

Reconciliation of Net Earnings as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's net earnings reported in accordance with previous GAAP to its net earnings in accordance with IFRS for the three and twelve months ended December 31, 2010:

	Note	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2010
Net earnings as reported under previous GAAP		73	993
Differences increasing (decreasing) reported net earnings			
Depreciation of fair value adjustment on the refining assets	A	48	126
Depletion due to allocation of the full cost pool	B	(30)	(135)
Amortization of deferred asset	C	4	17
Stock-based compensation	E	4	9
Employee benefits	F	1	2
Gain (loss) on divestiture of assets	G	(3)	125
Exploration expense	H	(3)	(3)
Deferred income tax	I	(16)	(53)
		5	88
Net Earnings as reported under IFRS		78	1,081

Reconciliation of Comprehensive Income as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's comprehensive income reported in accordance with previous GAAP to its comprehensive income in accordance with IFRS for the three and twelve months ended December 31, 2010:

	Note	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2010
Comprehensive income as reported under previous GAAP		(9)	980
Differences increasing (decreasing) reported comprehensive income			
Differences in net earnings		5	88
Foreign currency translation	J	56	84
Comprehensive income as reported under IFRS		52	1,152

Reconciliation of Cash from Operating, Investing and Financing Activities Under Previous GAAP to IFRS

The following is a reconciliation of the Company's cash from operating activities and cash from investing activities reported in accordance with previous GAAP to cash from operating activities and cash from investing activities in accordance with IFRS for the three and twelve months ended December 31, 2010:

	Note	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2010
Cash from operating activities as reported under previous GAAP		658	2,594
Differences increasing (decreasing)			
Exploration expense	H	(3)	(3)
Cash from operating activities as reported under IFRS		655	2,591
Cash from investing activities as reported under previous GAAP		(657)	(1,796)
Differences increasing (decreasing)			
Exploration expense	H	3	3
Cash from investing activities as reported under IFRS		(654)	(1,793)

There was no difference between previous GAAP and IFRS related to cash from financing activities.

24. FIRST TIME ADOPTION OF IFRS (continued)

Notes:

A) Refining Property, Plant and Equipment

At January 1, 2010, Cenovus elected to measure its refining assets at fair value and to use that fair value as its deemed cost on transition to IFRS. The fair value of the refining assets was determined to be US$4,543 million, US$2,272 million net to Cenovus, which resulted in the carrying value of the refining assets exceeding the fair value. Therefore, the carrying value of property, plant and equipment was reduced by $2,585 million at the Transition Date which represents Cenovus's share of the reduction to fair value. The decrease in paid in surplus represents the difference between the above fair value and the carrying value under previous GAAP.

In December 2010, it was determined that a processing unit at the Borger Refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, under previous GAAP, an impairment of $37 million was recorded. Under IFRS, however, the impairment was only $14 million due to the IFRS 1 election to use the fair value as deemed cost. Therefore DD&A expense under IFRS was reduced by $23 million.

The lower carrying value under IFRS and the impairment adjustment noted above resulted in lower DD&A expense for the three and twelve months ended December 31, 2010 of $48 million and $126 million, respectively.

B) Oil and Gas Property, Plant and Equipment

Under previous GAAP, costs accumulated within each cost centre for oil and gas properties were depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on a country-by-country cost centre basis (full cost accounting). Under IFRS, costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on an area-by-area basis. This resulted in an increase in DD&A expense for the three and twelve months ended December 31, 2010 of $30 million and $135 million, respectively. There was no impact on the opening balance sheet as a result of this allocation.

C) Impairment of Deferred Asset

Under previous GAAP, other assets included a deferred asset, which represented the disproportionate interest received in 2007 and 2008 (15 percent in 2007 and 35 percent in 2008) that arose from the acquisition of the Borger Refinery in 2007. On transition to IFRS, it was determined that as a result of the reduction in the carrying value of the refineries due to the fair value election, the deferred asset was impaired and therefore was written off. Paid in surplus was decreased by the carrying value of the asset under previous GAAP of $121 million. Under previous GAAP, the deferred asset was amortized over 10 years. As such, DD&A expense under IFRS decreased by $4 million and $17 million for the three and twelve months ended December 31, 2010, respectively.

D) Decommissioning Liabilities

As discussed above, the Company elected to apply the exemption to measure decommissioning liabilities at the Transition Date in accordance with IAS 37. As such, the Company re-measured the decommissioning liabilities as at the Transition Date using the period end credit-adjusted risk-free discount rate and recognized an increase of $38 million to the decommissioning liability.

Consistent with IFRS, decommissioning liabilities under previous GAAP were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition. However, changes to the discount rate were not reflected in the decommissioning liability or the related asset under previous GAAP. Under IFRS, the discount rate is adjusted each reporting period to reflect the current market rate. As at December 31, 2010, property, plant and equipment and the decommissioning liability were $154 million higher under IFRS. There was minimal impact to the unwinding of the discount for the three and twelve month periods ended December 31, 2010.

E) Stock-Based Compensation

Under previous GAAP, obligations for payments under Cenovus's stock option plan (with associated tandem stock appreciation rights) were accrued for using the intrinsic method. Under IFRS, these obligations are accrued for using the fair value method. As a result of the re-measurement of the liability as at January 1, 2010 a charge of $27 million was recognized in paid in surplus with an increase to accounts payable and accrued liabilities of $31 million and an increase to accounts receivable and accrued revenues of $4 million. The adjustment to earnings after January 1, 2010 is a result of the differences in the measurement basis under IFRS and previous GAAP. A

24. FIRST TIME ADOPTION OF IFRS (continued)

portion of the compensation costs have been capitalized in property, plant and equipment as the costs are directly attributable to the asset. As at December 31, 2010 property, plant and equipment has been reduced by $4 million.

F) Employee Benefits

Cenovus elected under IFRS 1 to recognize all unamortized actuarial gains and losses on the defined benefit pension and other post-employment benefits plans at the Transition Date resulting in a $7 million increase to other liabilities, a $7 million decrease to other assets and a $14 million charge to paid in surplus. Under previous GAAP, the actuarial losses continued to be amortized and as such for the three months ended December 31, 2010 operating expense decreased by $1 million. For the twelve months ended December 31, 2010 both general and administrative and operating expense decreased by $1 million.

G) Gains/Losses on Divestiture of Assets

Under previous GAAP, proceeds on the divestiture of oil and gas properties were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20 percent or more. Under IFRS, all gains and losses are recognized on oil and gas property divestitures and calculated as the difference between net proceeds and the carrying value of the net assets disposed. Accordingly, a loss of $3 million was recognized for the three months ended December 31, 2010. A gain of $125 million for the twelve months ended December 31, 2010 was recognized under IFRS. At December 31, 2010 the carrying value of property, plant and equipment increased $133 million and goodwill and decommissioning liabilities were reduced by $14 million and $6 million, respectively.

H) Pre-Exploration Expense

Under IFRS, costs incurred prior to obtaining the legal right to explore must be expensed whereas under previous GAAP these costs were capitalized in the full cost pool. For the three and twelve months ended December 31, 2010, $3 million of pre-exploration costs were expensed as exploration expense under IFRS. The accounting policy difference has resulted in cash from operating activities decreasing by $3 million and cash from investing activities increasing by a corresponding amount for the year ended December 31, 2010.

I) Deferred Income Taxes

The increase in paid in surplus of $986 million at the Transition Date related to deferred income taxes, reflects the change in temporary differences resulting from the IFRS 1 exemptions applied. For the twelve months ended December 31, 2010 deferred income taxes increased by $53 million to reflect the changes in temporary differences resulting from the IFRS adjustments described above plus a $9 million adjustment to recognize the deferred tax benefit on an intercompany transfer of oil and gas properties. Deferred tax expense increased by $16 million for the three months ended December 31, 2010 as a result of the changes during the period in temporary differences arising from the IFRS adjustments described above.

J) Currency Translation Adjustments

As previously noted, Cenovus elected to deem all cumulative currency translation differences for all foreign operations to be zero at the Transition Date. All foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date were transferred to paid in surplus.

In addition, AOCI is affected by the revaluation of the adjustments noted above that reside in a foreign operation notably the reduction in the carrying value of the Refining property, plant and equipment, the impairment of the deferred asset and the associated deferred income tax payable. The table below identifies the cumulative balance sheet impact for the period ended December 31, 2010:

Increase (Decrease)	December 31, 2010
Assets	
Refining property, plant and equipment	125
Other assets	5
Liabilities and Equity	
Deferred income tax liability	46
Accumulated other comprehensive income	98
Paid in surplus	(14)

24. FIRST TIME ADOPTION OF IFRS (continued)

K) Reclassifications

Exploration and evaluation ("E&E") assets

Under previous GAAP, E&E assets were included in property, plant and equipment whereas under IFRS, E&E assets are separately disclosed. Therefore at January 1, 2010 the Company reclassified $580 million from property, plant and equipment to E&E assets. At December 31, 2010, $713 million were reclassified.

Finance costs and interest income

Under previous GAAP, interest was reported on a net basis. Under IFRS, interest expense is included in finance costs and interest income is reported separately.

In addition, under previous GAAP, the unwinding of the discount on decommissioning liabilities was included as accretion expense in the Consolidated Statements of Earnings and Comprehensive Income. Under IFRS this amount has been reclassified to finance costs.

Gains/losses on risk management

Under previous GAAP, gains and losses from crude oil and natural gas commodity price risk management activities were recorded in gross revenues. Under IFRS, these activities do not meet the definition of revenue and therefore have been reclassified to (gain) loss on risk management in the Consolidated Statements of Earnings and Comprehensive Income. In addition, risk management activities related to power and the refining business have been reclassified to gain (loss) on risk management activities from operating expense and purchased product, respectively.

Assets and liabilities classified as held for sale

Under previous GAAP, assets held for sale and liabilities related to assets held for sale were included as part of non-current assets and liabilities. Under IFRS, non-current assets that meet the definition of held for sale are required to be classified as current.

Deferred income tax

A net deferred income tax asset has arisen related to the U.S. foreign operations, due to the adjustments noted above. Consistent with previous GAAP, a deferred income tax asset may not be offset against a deferred income tax liability in a different tax jurisdiction.

L) Net Earnings Per Share

Basic earnings per share

Basic earnings per share under IFRS was impacted by the IFRS earnings adjustments discussed above.

Diluted earnings per share

Under previous GAAP, Cenovus's TSARs, which may be cash or equity settled at the option of the holder, had no dilutive effect on diluted earnings per share because cash settlement was assumed. Under IFRS, the more dilutive of cash settlement and share settlement is required to be used in calculating diluted earnings per share. The following tables identify the difference between previous GAAP and IFRS:

For the three months ended December 31, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	73	752.2	$0.10	78	752.2	$0.10
Dilutive effect of exercised Cenovus TSARs	-	0.5		-	0.5	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	2.2	
Net earnings per share - diluted	73	752.7	$0.10	78	754.9	$0.10

24. FIRST TIME ADOPTION OF IFRS (continued)

For the twelve months ended December 31, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	993	751.9	$1.32	1,081	751.9	$1.44
Dilutive effect of exercised Cenovus TSARs	-	0.8		-	0.8	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	1.3	
Net earnings per share - diluted	993	752.7	$1.32	1,081	754.0	$1.43

M) Debt to Capitalization Ratio

The transition to IFRS resulted in changes to the Company’s Debt to Capitalization ratio as follows:

	Previous GAAP		IFRS	
	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010
Long-Term Debt	3,432	3,656	3,432	3,656
Debt	3,432	3,656	3,432	3,656
Shareholders’ Equity	10,022	9,608	8,395	7,809
Total Capitalization	13,454	13,264	11,827	11,465
Debt to Capitalization ratio	26%	28%	29%	32%

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**16,185**	**4,480**	3,989	4,085	3,631	13,090	3,471	3,069	3,217	3,333
Less: Royalties	**489**	**151**	131	76	131	449	108	107	123	111
Revenues	**15,696**	**4,329**	3,858	4,009	3,500	12,641	3,363	2,962	3,094	3,222
Operating Cash Flow										
Crude Oil and Natural Gas Liquids										
Foster Creek and Christina Lake	**905**	**274**	213	245	173	761	188	184	176	213
Pelican Lake	**305**	**69**	83	76	77	286	56	73	71	86
Conventional	**881**	**246**	209	218	208	758	188	183	161	226
Natural Gas	**777**	**188**	200	197	192	1,084	252	248	269	315
Other Upstream Operations	**13**	**4**	2	3	4	16	6	(1)	8	3
	2,881	**781**	707	739	654	2,905	690	687	685	843
Refining and Marketing	**981**	**238**	238	325	180	76	125	(26)	(20)	(3)
Operating Cash Flow [1]	**3,862**	**1,019**	945	1,064	834	2,981	815	661	665	840
Cash Flow Information										
Cash from Operating Activities	**3,273**	**952**	921	769	631	2,591	655	645	471	820
Deduct (Add back):										
Net change in other assets and liabilities	**(82)**	**(20)**	(17)	(16)	(29)	(55)	(14)	(13)	(13)	(15)
Net change in non-cash working capital	**79**	**121**	145	(154)	(33)	234	24	149	(53)	114
Cash Flow [2]	**3,276**	**851**	793	939	693	2,412	645	509	537	721
Per share - Basic	**4.34**	**1.13**	1.05	1.25	0.92	3.21	0.86	0.68	0.71	0.96
- Diluted	**4.32**	**1.12**	1.05	1.24	0.91	3.20	0.85	0.68	0.71	0.96
Operating Earnings [3]	**1,239**	**332**	303	395	209	799	147	156	143	353
Per share - Diluted	**1.64**	**0.44**	0.40	0.52	0.28	1.06	0.19	0.21	0.19	0.47
Net Earnings	**1,478**	**266**	510	655	47	1,081	78	295	183	525
Per share - Basic	**1.96**	**0.35**	0.68	0.87	0.06	1.44	0.10	0.39	0.24	0.70
- Diluted	**1.95**	**0.35**	0.67	0.86	0.06	1.43	0.10	0.39	0.24	0.70
Effective Tax Rates using										
Net Earnings	**33.0%**					17.1%				
Operating Earnings, excluding divestitures	**34.5%**					23.2%				
Canadian Statutory Rate	**26.7%**					28.2%				
U.S. Statutory Rate	**37.5%**					37.5%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**1.012**	**0.978**	1.020	1.033	1.015	0.971	0.987	0.962	0.973	0.961
Period end	**0.983**	**0.983**	0.963	1.037	1.029	1.005	1.005	0.971	0.943	0.985

(1) Operating Cash Flow is a non-GAAP measure defined as revenue less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities.
(2) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.
(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management accounting gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)	2011	2010
Debt to Capitalization [4], [5]	**27%**	29%
Debt to Adjusted EBITDA [5], [6]	**1.0x**	1.3x
Return on Capital Employed [7]	**13%**	11%
Return on Common Equity [8]	**17%**	13%

(4) Capitalization is a non-GAAP measure defined as Debt plus Shareholders' Equity.
(5) Debt includes the Company's short-term borrowings plus long-term debt, including the current portion of long-term debt.
(6) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.
(7) Calculated, on a trailing twelve-month basis, as net earnings before after tax interest divided by average Shareholders' Equity plus average Debt.
(8) Calculated, on a trailing twelve-month basis, as net earnings divided by average Shareholders' Equity.

Common Share Information	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period end	**754.5**	**754.5**	754.3	754.1	753.9	752.7	752.7	752.0	751.8	751.7
Average - Basic	**754.0**	**754.4**	754.3	754.1	753.2	751.9	752.2	751.9	751.7	751.5
Average - Diluted	**757.7**	**757.1**	757.8	758.0	758.1	754.0	754.9	753.8	753.8	752.4
Price Range *($ per share)*										
TSX - C$										
High	**38.98**	**37.11**	38.38	38.98	38.90	33.40	33.40	31.00	30.63	27.84
Low	**28.85**	**28.85**	29.87	31.73	31.15	24.26	28.31	26.19	25.83	24.26
Close	**33.83**	**33.83**	32.27	36.40	38.30	33.28	33.28	29.59	27.40	26.53
NYSE - US$										
High	**40.73**	**37.35**	40.61	40.73	40.06	33.37	33.37	30.12	30.66	26.79
Low	**27.15**	**27.15**	29.02	32.48	31.11	22.87	27.78	24.61	23.84	22.87
Close	**33.20**	**33.20**	30.71	37.66	39.38	33.24	33.24	28.77	25.79	26.21
Dividends Paid ($ per share)	**$ 0.80**	**$ 0.20**	$ 0.20	$ 0.20	$ 0.20	$0.80	$0.20	$0.20	$0.20	$0.20
Share Volume Traded *(millions)*	**873.7**	**213.3**	239.8	215.9	204.7	787.7	153.3	188.0	241.9	204.5

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *($ millions)*	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Oil Sands										
Foster Creek	**429**	**139**	110	77	103	277	110	59	52	56
Christina Lake	**472**	**126**	117	121	108	346	105	93	85	63
Total	**901**	**265**	227	198	211	623	215	152	137	119
Pelican Lake	**317**	**132**	70	31	84	104	37	17	28	22
Other Oil Sands	**197**	**68**	9	11	109	130	52	16	19	43
	1,415	**465**	306	240	404	857	304	185	184	184
Conventional	**788**	**330**	193	89	176	526	220	136	68	102
Refining and Marketing	**393**	**73**	101	117	102	656	139	147	166	204
Corporate	**127**	**35**	31	30	31	76	38	11	26	1
Capital Investment	**2,723**	**903**	631	476	713	2,115	701	479	444	491
Acquisitions	**71**	**49**	1	2	19	86	48	4	34	-
Divestitures	**(173)**	**(164)**	-	(5)	(4)	(307)	5	(168)	(72)	(72)
Net Acquisition and Divestiture Activity	**(102)**	**(115)**	1	(3)	15	(221)	53	(164)	(38)	(72)
Net Capital Investment	**2,621**	**788**	632	473	728	1,894	754	315	406	419

Operating Statistics - Before Royalties

Upstream Production Volumes	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands - Heavy										
Foster Creek	**54,868**	**55,045**	56,322	50,373	57,744	51,147	52,183	50,269	51,010	51,126
Christina Lake	**11,665**	**19,531**	10,067	7,880	9,084	7,898	8,606	7,838	7,716	7,420
Total	**66,533**	**74,576**	66,389	58,253	66,828	59,045	60,789	58,107	58,726	58,546
Pelican Lake	**20,424**	**20,558**	20,363	19,427	21,360	22,966	21,738	23,259	23,319	23,565
	86,957	**95,134**	86,752	77,680	88,188	82,011	82,527	81,366	82,045	82,111
Conventional Liquids										
Heavy Oil	**15,657**	**15,512**	15,305	15,378	16,447	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	**30,524**	**32,530**	30,399	27,617	31,539	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids [(1)]	**1,101**	**1,097**	1,040	1,087	1,181	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	**134,239**	**144,273**	133,496	121,762	137,355	129,187	129,593	128,067	128,566	130,549
Natural Gas (MMcf/d)										
Oil Sands	**37**	**38**	39	37	32	43	39	44	46	45
Conventional	**619**	**622**	617	617	620	694	649	694	705	730
Total Natural Gas	**656**	**660**	656	654	652	737	688	738	751	775

(1) Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of realized gain (loss) on risk management)*	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek [(1)]	**16.8%**	**21.7%**	20.6%	3.3%	21.2%	16.2%	20.4%	17.9%	19.0%	9.7%
Christina Lake	**5.2%**	**4.7%**	5.7%	6.3%	4.8%	3.9%	3.6%	3.9%	4.4%	4.0%
Pelican Lake	**11.5%**	**9.1%**	12.7%	9.7%	13.9%	21.1%	21.2%	18.5%	23.3%	21.4%
Conventional										
Weyburn	**24.1%**	**24.8%**	23.9%	23.6%	24.3%	22.2%	18.8%	23.2%	23.3%	23.3%
Other	**8.3%**	**8.1%**	9.0%	8.5%	7.6%	8.2%	7.2%	7.1%	9.1%	9.1%
Natural Gas Liquids	**1.7%**	**1.8%**	1.4%	2.3%	1.3%	1.9%	1.0%	2.4%	2.0%	2.1%
Natural Gas	**1.7%**	**1.9%**	1.5%	1.2%	2.3%	1.6%	1.7%	2.4%	1.7%	2.8%

(1) Foster Creek royalty rate was significantly lower in Q2 2011 as a result of the Alberta Department of Energy approving the expansion phases F, G and H capital investment to be included as part of the existing royalty calculation.

Refining	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [(1)]										
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**401**	**424**	413	406	362	386	410	401	379	355
Crude utilization	**89%**	**94%**	91%	90%	80%	86%	91%	89%	84%	79%
Refined products *(Mbbls/d)*	**419**	**442**	426	422	383	405	434	409	398	377

(1) Represents 100% of the Wood River and Borger refinery operations.

Selected Average Benchmark Prices	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
West Texas Intermediate ("WTI")	**95.11**	**94.06**	89.54	102.34	94.60	79.61	85.24	76.21	78.05	78.88
Western Canadian Select ("WCS")	**77.96**	**83.58**	71.92	84.70	71.74	65.38	67.12	60.56	63.96	69.84
Differential - WTI-WCS	**17.15**	**10.48**	17.62	17.64	22.86	14.23	18.12	15.65	14.09	9.04
Condensate - (C5 @ Edmonton)	**105.34**	**108.74**	101.48	112.33	98.90	81.91	85.24	74.53	82.87	84.98
Differential - WTI-Condensate (premium)/discount	**(10.23)**	**(14.68)**	(11.94)	(9.99)	(4.30)	(2.30)	-	1.68	(4.82)	(6.10)
Refining Margins 3-2-1 Crack Spreads [(1)] *(US$/bbl)*										
Chicago	**24.55**	**19.23**	33.35	29.00	16.62	9.33	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	**25.26**	**20.75**	34.04	27.19	19.04	9.48	9.12	10.60	11.38	6.82
Natural Gas Prices										
AECO *($/GJ)*	**3.48**	**3.29**	3.53	3.54	3.58	3.91	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	**4.04**	**3.55**	4.19	4.31	4.11	4.39	3.80	4.38	4.09	5.30
Differential - NYMEX/AECO *(US$/MMBtu)*	**0.31**	**0.17**	0.34	0.42	0.29	0.40	0.28	0.78	0.32	0.19

(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 ultra low sulphur diesel.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results
($, excluding impact of realized gain (loss) on risk management)

	2011					2010				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* [1]										
Price	**67.38**	**75.96**	62.68	72.23	59.50	58.76	58.76	58.51	54.75	63.33
Royalties	**10.82**	**15.81**	12.38	2.30	11.92	9.08	11.41	9.56	9.38	5.76
Transportation and blending	**3.04**	**3.20**	2.73	2.82	3.41	2.42	2.54	2.40	2.40	2.33
Operating	**11.34**	**11.31**	11.11	11.57	11.40	10.40	9.93	10.32	10.36	11.04
Netback	**42.18**	**45.64**	36.46	55.54	32.77	36.86	34.88	36.23	32.61	44.20
Heavy Oil - Christina Lake *($/bbl)* [1]										
Price	**61.86**	**66.69**	54.52	67.06	54.67	57.96	58.42	56.45	54.99	62.27
Royalties	**3.03**	**2.97**	2.87	3.98	2.44	2.14	2.05	2.04	2.19	2.28
Transportation and blending	**3.53**	**2.98**	4.54	3.51	3.69	3.54	1.54	3.69	4.52	4.47
Operating	**20.20**	**17.96**	23.01	23.41	19.09	16.47	17.16	15.88	16.59	16.26
Netback	**35.10**	**42.78**	24.10	36.16	29.45	35.81	37.67	34.84	31.69	39.26
Heavy Oil - Pelican Lake *($/bbl)* [1]										
Price	**73.07**	**88.67**	66.76	78.26	64.66	62.65	61.38	58.93	62.05	68.04
Royalties	**7.91**	**6.98**	8.23	7.40	8.63	12.96	12.76	10.62	14.06	14.34
Transportation and blending	**4.14**	**12.19**	1.87	2.02	2.44	1.42	1.04	1.77	1.52	1.30
Operating	**14.86**	**16.49**	14.31	13.40	15.35	12.71	13.44	13.05	13.34	11.13
Netback	**46.16**	**53.01**	42.35	55.44	38.24	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands *($/bbl)* [1]										
Price	**67.99**	**76.39**	62.93	73.02	60.35	59.76	59.35	58.41	56.83	64.61
Royalties	**9.17**	**11.72**	10.46	3.65	10.08	9.53	10.79	9.30	10.03	7.94
Transportation and blending	**3.36**	**4.75**	2.68	2.71	3.18	2.25	2.08	2.35	2.35	2.23
Operating	**13.27**	**13.54**	13.02	13.27	13.23	11.66	11.49	11.74	11.82	11.57
Netback	**42.19**	**46.38**	36.77	53.39	33.86	36.32	34.99	35.02	32.63	42.87
Heavy Oil - Conventional *($/bbl)* [1]										
Price	**74.17**	**81.49**	67.96	78.47	69.17	63.18	60.45	59.40	61.35	71.16
Royalties	**10.75**	**11.85**	11.33	10.98	9.04	9.01	8.01	7.29	9.65	10.99
Transportation and blending	**1.27**	**1.34**	1.80	0.91	1.05	0.56	0.45	0.60	0.60	0.59
Operating	**13.77**	**16.34**	12.40	13.66	12.78	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	**0.32**	**0.34**	0.17	0.22	0.51	0.19	0.05	0.17	0.10	0.44
Netback	**48.06**	**51.62**	42.26	52.70	45.79	41.22	38.77	39.93	38.00	47.80
Total Heavy Oil *($/bbl)* [1]										
Price	**68.98**	**77.16**	63.69	73.98	61.80	60.33	59.53	58.59	57.57	65.76
Royalties	**9.42**	**11.74**	10.59	4.93	9.91	9.44	10.36	8.95	9.97	8.48
Transportation and blending	**3.02**	**4.23**	2.55	2.40	2.83	1.97	1.83	2.04	2.06	1.94
Operating	**13.35**	**13.96**	12.93	13.34	13.16	11.75	11.75	11.68	12.02	11.53
Production and mineral taxes	**0.05**	**0.05**	0.03	0.04	0.08	0.03	0.01	0.03	0.02	0.08
Netback	**43.14**	**47.18**	37.59	53.27	35.82	37.14	35.58	35.89	33.50	43.73
Light and Medium Oil *($/bbl)*										
Price	**85.40**	**90.90**	79.57	94.30	77.39	71.63	72.98	68.37	66.14	78.78
Royalties	**11.54**	**12.12**	10.74	12.82	10.58	9.30	7.69	9.32	10.17	10.05
Transportation and blending	**2.00**	**1.99**	1.90	2.22	1.92	1.66	1.89	1.81	1.51	1.45
Operating	**14.38**	**15.12**	14.37	12.96	14.86	12.18	12.69	12.00	12.87	11.18
Production and mineral taxes	**2.27**	**2.63**	2.40	2.77	1.32	2.55	2.45	2.44	3.08	2.25
Netback	**55.21**	**59.04**	50.16	63.53	48.71	45.94	48.26	42.80	38.51	53.85
Total Crude Oil *($/bbl)*										
Price	**72.80**	**80.49**	67.37	78.71	65.32	62.98	62.75	60.86	59.51	68.87
Royalties	**9.92**	**11.83**	10.62	6.77	10.06	9.41	9.72	9.03	10.01	8.85
Transportation and blending	**2.78**	**3.69**	2.40	2.35	2.63	1.90	1.84	1.99	1.94	1.83
Operating	**13.59**	**14.24**	13.26	13.25	13.54	11.85	11.98	11.75	12.21	11.44
Production and mineral taxes	**0.57**	**0.67**	0.58	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**45.94**	**50.06**	40.51	55.67	38.73	39.20	38.62	37.50	34.64	46.16
Natural Gas Liquids *($/bbl)*										
Price	**76.84**	**82.26**	74.38	80.32	70.67	61.00	63.60	54.43	58.71	67.42
Royalties	**1.34**	**1.51**	1.06	1.87	0.93	1.12	0.75	1.29	1.16	1.39
Netback	**75.50**	**80.75**	73.32	78.45	69.74	59.88	62.85	53.14	57.55	66.03
Total Liquids *($/bbl)*										
Price	**72.84**	**80.50**	67.43	78.72	65.37	62.96	62.75	60.80	59.50	68.85
Royalties	**9.84**	**11.75**	10.55	6.72	9.98	9.33	9.63	8.96	9.93	8.78
Transportation and blending	**2.76**	**3.66**	2.38	2.33	2.60	1.88	1.82	1.97	1.94	1.83
Operating	**13.47**	**14.13**	13.16	13.13	13.43	11.74	11.82	11.64	12.10	11.34
Production and mineral taxes	**0.56**	**0.67**	0.57	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**46.21**	**50.29**	40.77	55.87	39.00	39.39	38.89	37.64	34.82	46.31
Total Natural Gas *($/Mcf)*										
Price	**3.65**	**3.35**	3.72	3.71	3.82	4.09	3.55	3.68	3.78	5.27
Royalties	**0.06**	**0.06**	0.05	0.04	0.08	0.07	(0.04)	0.08	0.07	0.14
Transportation and blending	**0.15**	**0.14**	0.15	0.14	0.17	0.17	0.16	0.15	0.15	0.21
Operating	**1.10**	**1.22**	0.99	0.98	1.19	0.95	1.02	0.93	0.92	0.93
Production and mineral taxes	**0.04**	**0.01**	0.03	0.05	0.06	0.02	0.02	0.03	(0.04)	0.07
Netback	**2.30**	**1.92**	2.50	2.50	2.32	2.88	2.39	2.49	2.68	3.92
Total *($/BOE)*										
Price	**49.75**	**53.48**	46.97	51.81	46.83	44.01	42.82	41.49	41.46	50.16
Royalties	**5.55**	**6.65**	5.91	3.64	5.85	4.93	4.90	4.73	5.26	4.81
Transportation and blending	**1.91**	**2.39**	1.70	1.61	1.92	1.45	1.40	1.42	1.43	1.53
Operating [2]	**10.35**	**11.09**	9.88	9.69	10.68	8.76	9.07	8.63	8.87	8.46
Production and mineral taxes	**0.41**	**0.40**	0.39	0.49	0.36	0.37	0.35	0.38	0.24	0.52
Netback	**31.53**	**32.95**	29.09	36.38	28.02	28.50	27.10	26.33	25.66	34.84

[1] The 2011 YTD heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek - $41.74/bbl; Christina Lake - $47.07/bbl; Pelican Lake - $16.32/bbl; Heavy Oil - Oil Sands - $36.57/bbl; Heavy Oil - Conventional - $12.73/bbl and Total Heavy Oil - $32.76/bbl.

[2] 2011 YTD operating costs include costs related to long-term incentives of $0.17/BOE (2010 - $0.16/BOE).

Impact of realized gain (loss) on risk management

Liquids *($/bbl)*	**(2.79)**	**(3.15)**	0.75	(6.44)	(2.67)	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas *($/Mcf)*	**0.87**	**1.10**	0.76	0.74	0.89	1.07	1.50	1.09	1.22	0.53
Total *($/BOE)*	**0.86**	**1.22**	2.49	(1.25)	0.83	2.99	3.65	3.77	3.37	1.20