SUNCOR ENERGY INC.

2012 Annual Report

SUNCOR ENERGY Inc. (Suncor) is Canada's premier integrated energy company. Suncor's operations include oil sands development and upgrading, conventional and offshore oil and gas production, petroleum refining, and product marketing under the Petro-Canada brand. While working to develop petroleum resources responsibly, Suncor is also developing a growing renewable energy portfolio. Suncor's common shares (symbol: SU) are listed on the TSX and NYSE.

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The following is a list of abbreviations that may be used in this Annual Report:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d or kbpd	thousands of barrels per day
mmbbls	millions of barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
m^3	cubic metres
m^3/d	cubic metres per day
MW	megawatts
GJ	gigajoule

Places and Currencies

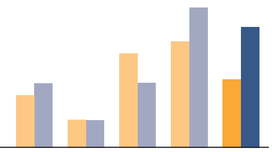
U.S.	*United States*
U.K.	*United Kingdom*
B.C.	*British Columbia*
$ or Cdn$	*Canadian dollars*
US$	*United States dollars*
£	*Pounds sterling*
€	*Euros*

Financial and Business Environment

IFRS	*International Financial Reporting Standards*
GAAP	*Generally Accepted Accounting Principles*
TSX	*Toronto Stock Exchange*
NYSE	*New York Stock Exchange*
DD&A	*Depreciation, depletion and amortization*
WTI	*West Texas Intermediate*
WCS	*Western Canadian Select*
SCO	*Synthetic crude oil*
NYMEX	*New York Mercantile Exchange*
NGL(s)	*Natural gas liquid(s)*

FINANCIAL HIGHLIGHTS[1][2]

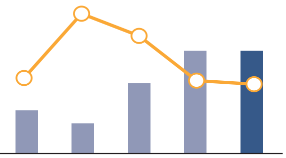
Earnings
($ millions)



	2008	2009	2010	2011	**2012**
Net earnings	2 137	1 146	3 829	4 304	**2 783**
Operating earnings[3]	2 617	1 115	2 634	5 674	**4 890**

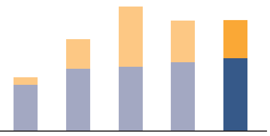
2012 net earnings includes an after-tax impairment charge of $1.487 billion for the Voyageur upgrader project.

Net Debt and Cash Flow from Operations[3]
($ millions)



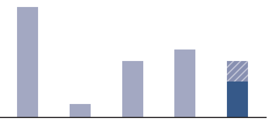
	2008	2009	2010	2011	**2012**
Net debt (at year end)	7 226	13 377	11 254	6 976	**6 632**
Cash flow from operations[3]	4 057	2 799	6 656	9 746	**9 745**

Production
(mboe/d)



	2008	2009	2010	2011	**2012**
Exploration and Production	36.7	149.3	296.9	206.7	**189.9**
Oil Sands	228.0	306.7	318.2	339.3	**359.2**
Total	264.7	456.0	615.1	546.0	**549.1**

Return on Capital Employed[3]
(%)



2008	2009	2010	2011	**2012**
22.5	2.6	11.4	13.8	**7.3**

2012 return on capital employed was impacted by approximately 4% due to an after-tax impairment of $1.487 billion for the Voyageur upgrader project.

Other Key Indicators[1][2]

Year ended December 31	2008	2009	2010	2011	**2012**
Financial (dollars per common share)					
Net earnings – basic	2.29	0.96	2.45	2.74	**1.80**
Net earnings – diluted	2.26	0.95	2.43	2.67	**1.79**
Operating earnings[3] – basic	2.81	0.93	1.69	3.61	**3.17**
Cash flow from operations[3] – basic	4.36	2.34	4.25	6.20	**6.31**
Dividend	0.20	0.30	0.40	0.43	**0.50**
Financial ($ millions)					
Operating revenues (net of royalties)[4]	17 098	17 459	31 315	38 339	**38 208**
Capital and exploration expenditures	8 020	4 267	6 010	6 850	**6 959**
Total assets	32 528	69 746	68 607	74 777	**76 449**
Market Price of Common Shares (Closing as at December 31)					
TSX (Cdn$)	23.72	37.21	38.28	29.38	**32.71**
NYSE (US$)	19.50	35.31	38.29	28.83	**32.98**
Key Metrics					
Total debt to total debt plus shareholders' equity (%)	35	29	26	22	**22**
Net debt to cash flow from operations (times)[3]	1.8	4.8	1.7	0.7	**0.7**

(1) Amounts for 2010 to 2012 are based on information prepared in accordance with IFRS. Amounts for 2008 and 2009 are presented in accordance with Canadian GAAP in effect prior to January 1, 2011 (Previous GAAP). Users of this information are cautioned that 2008 and 2009 results may not be directly comparable with those for 2010 through 2012.

(2) Figures for 2008 and part of 2009 (January 1 to July 31) represent Suncor results prior to the merger of Suncor and Petro-Canada and do not reflect the results of Petro-Canada.

(3) Operating earnings, cash flow from operations and return on capital employed (which excludes major projects in progress) are non-GAAP financial measures, as are per common share and other key metrics which make use of these non-GAAP financial measures. See the Advisories section of this Annual Report.

(4) The company has reclassified prior years' operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

ADVISORIES

This Annual Report contains certain forward-looking information and forward-looking statements (collectively referred to as "forward-looking statements") within the meaning of applicable Canadian and U.S. securities laws. Forward-looking statements and other information is based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may" and similar expressions. Forward-looking statements and other information in this Annual Report include those statements identified in the Advisory – Forward Looking Information section of the Management Discussion and Analysis contained in this Annual Report (the MD&A). Forward-looking statements in our "Message to shareholders from the chief executive officer", "Suncor's integrated business model", and "Our scorecard" sections contained in this Annual Report include:

- Suncor's expectation that Firebag 4 will come in 15% under its $2.0 billion announced cost estimate, that the Firebag complex will reach production rates of 180,000 bbls/d over the next year, and that Suncor will become the largest in situ producer in the Oil Sands;
- Suncor's target for Oil Sands cash operating costs;
- Suncor's capital spending plans for 2013;
- Suncor's belief that oil sands crude remains an essential contributor to achieve North American energy self-sufficiency;
- Suncor's belief that it will be able to fund its capital program for 2013 entirely from cash from operations;
- Suncor's environmental goals to be achieved by 2015;
- Suncor's expectation for first oil for Hebron and Golden Eagle;
- Suncor's long-term growth and business strategies;
- Suncor's belief that its focus on reliability, combined with ongoing initiatives to reduce Suncor's operational risk, will effectively position the company to consistently deliver strong results;
- Suncor's belief that the advancement of various debottlenecking projects in 2013 will provide further cost efficiencies and higher returns;
- Suncor's 2013 production and refinery utilization guidance and other targets; and
- Suncor's expectation that its high quality in situ reserves and resources will enable the company to sustain its position as a leader in in situ production.

Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them. Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout the MD&A, including under the heading Risk Factors, and the company's 2012 Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov, which risk factors are incorporated by reference herein. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

All figures are presented in Cdn$ unless otherwise noted. Certain financial measures in this Annual Report – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings and Oil Sands cash operating costs are defined in the

Non-GAAP Financial Measures Advisory section of the MD&A and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of the MD&A. Cash flow from operations and ROCE are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of the MD&A. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, conversion on a 6:1 basis may be misleading as an indication of value.

2012 was an eventful year; most notably, a year where we strengthened Suncor's foundation for long-term business success. It was also a year of transition – for the oil sands industry, for Suncor, and myself, on a personal level. Suncor responded to increased scrutiny and tough market conditions by participating in the drive for environmental improvement, focusing on disciplined spending, optimizing our current asset base, and capitalizing on our integrated model. During this time, I also took on the role of Suncor's Chief Executive Officer.

As one of the architects of our strategy, I sought to refine and clarify our priorities to ensure we could successfully respond to changing market dynamics. As I made clear from the outset, the status quo is never an option in the constantly evolving energy business.

Shortly after my appointment, I brought together Suncor's Executive Leadership Team to review the company's strategy. We agreed on the need to focus on continuous improvement in every aspect of our business, while also driving down the cash costs of our Oil Sands business. We also agreed we would not pursue growth for the sake of growth. Rather, we'd seek profitable growth through a relentless focus on capital discipline and operational excellence, while delivering increased returns to our shareholders.

We see this as "our time" to lead – as a company uniquely positioned to deliver value, and grow in a disciplined manner, for decades to come.

2012: Strength Through Integration

Suncor had another strong financial year in 2012, largely through the strength of our integrated model. Operating earnings for the year were $4.890 billion and cash flow from operations was $9.745 billion. The company has demonstrated consistent cash flow, a strong balance sheet, and an ability to fund growth from internal resources while steadily increasing the return of cash to shareholders.

In a year when oil sands price realizations lagged significantly against world crude oil prices, Suncor's integrated model allowed us to capture 96% of world pricing for our production.

Suncor achieved production of 549,100 bbls/d in 2012, which included 359,200 bbls/d from Oil Sands and 189,900 boe/d from Exploration and Production operations. Oil Sands production (excluding Syncrude) in the fourth quarter of 2012 reached record levels of 342,800 bbls/day.

On the international front, Suncor successfully resumed operations in Libya following a change in the political regime and the lifting of sanctions. Operations in Syria remained suspended due to continuing political unrest and international sanctions. We have been consistent in our position that we will not operate unless we can do so safely, responsibly, and in compliance with international law.

A Relentless Focus on Operational Excellence

Operational excellence has been an ongoing focus for Suncor for several years. While work remains, particularly with respect to the reliability of our oil sands upgraders, I see many indications of progress and I'm confident in our ability to improve.

One reason for this confidence is the consistently strong execution on our Firebag in situ project. Production at Firebag Stage 3 was successfully ramped up and we expect to come in 15% under our $2.0 billion announced cost estimate on Firebag Stage 4, which achieved first oil ahead of schedule. Due to strong execution and commissioning of these projects, we expect to reach 180,000 bbls/d at the Firebag complex over the next year, making Suncor the largest in situ producer in the oil sands.

Another reason for this confidence is our Refining and Marketing business unit. Suncor's refineries demonstrated world-class reliability, with 95% utilization rates for the year. They also remained one of the most profitable in North America, based on earnings per barrel of crude refining capacity, as a result of reliable operations, favourable feedstock costs and profitable integration with our upstream production. Due to demonstrated reliability and continuous improvements, Suncor has increased the nameplate capacities of three out of four of our refineries since 2011.

To leverage this competence from our downstream business, we are looking for ways to share lessons learned by transferring key leaders of these refineries to our oil sands business.

Safety is a core value at Suncor; if we can't do a job safely, we won't do it. Safety performance is also an excellent indicator of operational discipline and we continue to make progress on our Journey to Zero program to reduce and ultimately eliminate workplace injuries. Total Injury Frequency (TIF) improved 21.1% over 2011, while Recordable Injury Frequency (RIF) improved 19.2% for the same period. While the company's improved performance is encouraging, our efforts are guided by the knowledge that there is still more work to be done.

Disciplined spending is another cornerstone of operational excellence. We recognize that Suncor needs to be a low-cost competitor in the industries we operate in, and we made significant progress towards this goal in 2012.

We continue to reduce our Oil Sands cash operating costs. We've made great progress driving costs out of the business through improvements in productivity, reliability and technology – lowering our Oil Sands cash operating costs per barrel by a full $2 in 2012. Our Oil Sands cash operating cost per barrel guidance of $33.50 to $36.50 for 2013 reflects our confidence that we can continue this positive trend.

Our strong cash flow provides us with a significant degree of flexibility. We have outlined three key priorities for that cash – investing in the long-term reliability of our existing assets, funding profitable growth and returning cash to shareholders in the form of dividends and share repurchases.

Our dividend has risen by 21% compounded annually over the past five years, including an 18% increase announced in May 2012. We also completed a $1.5 billion share repurchase program in September and authorized an additional $1.0 billion share repurchase program in 2012. We continue to see such repurchases as an attractive investment opportunity and in the best interests of our company and our shareholders.

As a result of disciplined and prudent spending, Suncor has a strong balance sheet, with record low debt-to-cash ratios as well as the expected ability to fund our capital program for 2013 entirely from cash from operations. In a volatile commodity price environment, our strategy has proven its strength by allowing us to fund profitable growth and return cash to shareholders.

Sustainable Development

Operating reliably and efficiently is not just about achieving increased production and profitability – it's also about how we become a more sustainable energy company. Every barrel of water we conserve and every emission we reduce at our operations mean lower input costs while also supporting our social licence to operate and grow.

Suncor is guided by a vision of sustainable development and a triple bottom line. We strive to be trusted stewards of valuable natural resources by leading the way to deliver economic prosperity, improve social well-being and maintain a healthy environment for today and tomorrow. It's how we do business and how we create value for our shareholders and strengthen the communities where we operate.

Investments in technology and innovation are critical to meeting this mandate. It's how we've cut greenhouse gases per barrel at our mining operations by half since 1990 and reduced our freshwater intake by more than 30% over the past six years. In 2012, we marked another milestone when we completed the infrastructure required to implement our new tailings reduction process. This technology has already allowed Suncor to accelerate reclamation plans, including the cancellation of five tailings ponds.

We continue to to be an industry leader by pursuing a series of strategic, transparent and beyond-compliance environmental performance goals. By 2015, we are targeting a 12% reduction in freshwater consumption, an increase in the reclamation of disturbed land area by 100%, a 10% improvement in energy efficiency and a 10% decrease in emissions – all compared to 2007 levels. All the targeted improvements are corporate-wide and absolute, except for energy efficiency, which is intensity-based. Deliberations are already underway on a set of post-2015 performance goals.

In an era of industry-wide growth, we recognize there are sustainability challenges that go beyond our operations. That's one reason I was excited to work with the CEOs and senior executives from more than a dozen other companies to launch Canada's Oil Sands Innovation Alliance (COSIA) in 2012.

COSIA is all about raising the bar on environmental performance in four key areas – water, land, tailings and greenhouse gases. It also builds on Suncor's track record by publicly committing to set specific performance goals. When it comes to the environment, we know the sum of what we do collectively will be greater than any individual effort. I also firmly believe COSIA is an example of the kind of collaboration – building bridges rather than walls – that is essential if we are to meet stakeholder expectations and ensure responsible and sustainable energy development.

The Path Forward: Disciplined Growth

Since my appointment as President and CEO, I have stressed that, while our growth plan included targets and goals, we would take the necessary time up front to ensure our projects deliver the highest possible value to our shareholders. The focus is on cost and quality, rather than achieving scheduled target dates. This drive for profitable growth underpins every decision we make.

We are applying this philosophy to all our capital spending. In particular, Suncor has been working with its respective partners to undertake detailed reviews of each of its planned Oil Sands Ventures growth projects, focusing on cost and quality, with a view to generating long-term value for shareholders.

Disciplined, profitable growth also requires making strategic choices in response to changing market conditions. This helps explain our view that the economics for the Voyageur upgrader project have become challenged. The North American energy market has changed since we initially proposed building a third oil sands upgrader. Most notably, with significantly higher volumes of tight oil being produced today, there is a potential surplus of light sweet crude on this continent. Because an upgrader takes advantage of the margin between light crudes and heavy crudes, a world with more tight oil puts the Voyageur economics on a more challenging footing. This led to an intensive review of the project with our partner, with a plan to make a sanctioning decision on the project by the end of the first quarter of 2013.

While tight oil production continues to grow, we believe oil sands crude remains an essential contributor to achieve North American energy self-sufficiency. At the same time, we see opportunities to tap into new markets. The recognition that we need to develop the required infrastructure to serve these additional markets also reflects our belief that it's simply good business to have more than one outlet for our product.

As a steward of Canada's valuable oil sands resources, we're well positioned to deliver. Our growth plan includes a prudent balance of in situ and mining projects, providing internal diversification, given the different capital and operating cost structures and potential technology advances associated with these two recovery methods.

Outside the oil sands, we are also targeting production growth in our conventional Exploration and Production division, including our working interest in the Hebron project off the east coast of Canada, which received project sanction in 2012, with first oil anticipated in late 2017, and our working interest the Golden Eagle project in the U.K. North Sea, which is expected to achieve first oil in late 2014 or early 2015.

Our $7.3 billion capital spending plan for 2013 is balanced between funding growth projects and sustaining assets, with a continued focus on capital discipline and the execution of lower cost, high return projects.

A Team Effort

Everything our company strives to achieve begins and ends with the expertise and commitment of Suncor's employees. I've been in the energy business for 35 years and I can tell you this: I have never worked with smarter, more dedicated people than those at Suncor.

Every day, our employees bring their best and demonstrate a passion to do their jobs the right way and with integrity. They understand we are all connected and part of something bigger.

I am also indebted to Suncor's Board of Directors, who oversee all aspects of governance and are outstanding stewards of stakeholders' interests. They excel at challenging our executive leadership team to continuously improve and responsibly grow our company.

When I look at our people, I know we can create and deliver strong value for you, our shareholders. On behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support.

Steve Williams
President and Chief Executive Officer

SUNCOR'S INTEGRATED BUSINESS MODEL

Suncor's integrated, diversified business model aims to maximize the market price received and net margins realized for upstream production. Suncor has operations in all stages of the oil and gas industry – from resource extraction through to refining and retail. This diverse portfolio of assets helps fund growth projects, balances some of the volatility in our revenues, and reduces our financing risk throughout fluctuating economic cycles.

How is Suncor's business model integrated and diversified?

Suncor processes synthetic and heavy crude oil into more valuable refined petroleum products.

In recent years, Suncor has made significant investments in its inland refineries to process oil sands production. The ability of Suncor's refineries to process oil sands production has enabled the company to capture the spread between WTI and global crude oil prices for the majority of its production, as prices for refined products are tied to global markets based on Brent crude.

Most of Suncor's remaining upstream crude oil production from the Exploration and Production segment receives prices directly based on Brent crude.

Suncor upgrades most of its bitumen production into more valuable light products.

Suncor's upgrading capacity enables the company to capture the spread between heavy and light crude oil prices by converting bitumen into light synthetic crude oil. Suncor's flexible upgrading configuration helps to optimize realizations by allowing the company to blend synthetic crude oil to specifications desired by its refining customers, or manage internal or external constraints.

Suncor reaches consumers of refined fuels and specialty products through its broad marketing network.

Suncor's retail, wholesale and lubricants channels further enhance margins beyond the refinery gate. Through its Petro-Canada$_{TM}$-branded outlets, Suncor remains a leading retailer in Canada.

Suncor optimizes price realizations for oil sands barrels by leveraging midstream infrastructure.

Suncor's Energy Trading business has entered into arrangements for pipeline and storage capacity that enables Suncor to optimize realizations for oil sands production.

Suncor's production and asset diversification helps protect against price movements in natural gas prices.

Although decreasing North American natural gas prices in recent years have reduced cash flow from natural gas assets in Western Canada, this impact was more than offset by lower operating costs for steam and power generation at our oil sands and refinery facilities.

How did Suncor's integrated model perform in 2012?

Despite challenging market conditions, Suncor delivered strong cash flow from operations in 2012, benefiting from a diverse set of assets, balanced with an integrated model that protected the company against volatile market pricing.

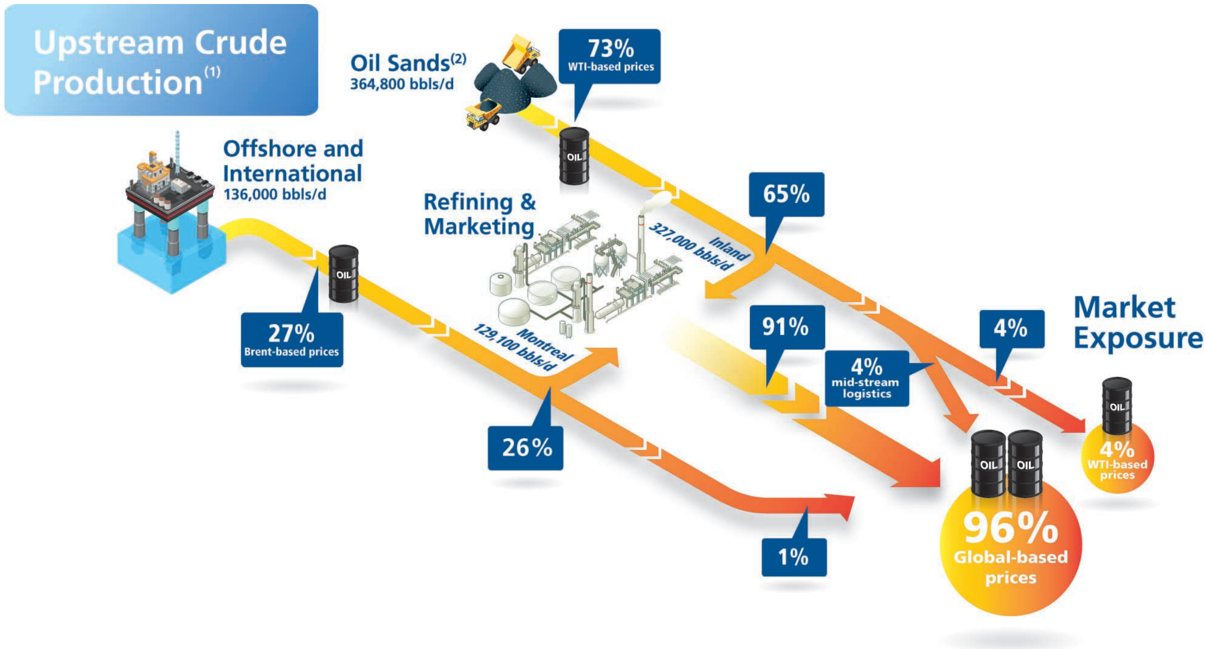
Suncor's integrated model protects against price movements in 2012.

Suncor's integrated model helped to protect against price movements in 2012, including fluctuating WTI, weakening synthetic crude oil prices relative to WTI, and wider light/heavy differentials. Simultaneously, Suncor benefited from strong crack spreads.

Suncor captured global crude pricing on approximately 96% of its upstream crude production.

Despite prices for WTI that were significantly discounted compared to Brent crude throughout most of 2012, Suncor captured prices tied to global crude markets on over 96% of its upstream crude production.

Approximately 73% of Suncor's upstream crude oil production in 2012 came from western Canada, which was largely comprised of production from our Oil Sands. While price realizations for this production were largely tied to WTI, Suncor's inland refinery capacity of 318,000 bbls/d enabled the company to realize global market prices for the majority of this production.



(1) Based on Suncor's production volumes and refinery throughput volumes in 2012.
(2) Includes 5,600 bbls/d of natural gas liquids and crude oil production from North America Onshore.

How is Suncor's integrated, diversified strategy positioned for the future?

Suncor continues to focus on integration.

As upstream production continues to grow, enhancing integration between Suncor's assets remains an important focus for the company. Suncor is currently reviewing projects to prepare the Montreal refinery to receive shipments of western Canadian feedstock and also continues to seek opportunities to optimize the crude throughput requirements at the company's inland refineries to enhance alignment with the production mix at Oil Sands.

Suncor's long-term growth strategy balances significant development projects with a focus on optimizing the current asset base and investing in new infrastructure to enhance marketing flexibility and takeaway capacity.

Suncor's significant reserves and resources base provides the company with a suite of profitable growth opportunities in the Oil Sands. Suncor is currently evaluating both mining and in situ opportunities. Near-term capital spending will also focus on optimizing the current asset base through various debottlenecking projects.

Capital projects in the Exploration and Production segment include Golden Eagle, the Hibernia Southern Extension Unit and Hebron. Suncor is currently exploring prospects in Norway and the U.K. North Sea.

Suncor and the oil sands industry are exploring multiple logistic opportunities to deliver oil sands crude to markets in the U.S. Gulf Coast, the Canadian West Coast, Ontario, Quebec and the Maritimes.

SUNCOR'S OPERATIONAL EXCELLENCE MANAGEMENT SYSTEM

Suncor is implementing a management system across the organization called the Operational Excellence Management System, or OEMS. It is aligned with internationally recognized management systems and is a best practice in the achievement of operational excellence. Management systems are used to define and continually improve how organizations work.

OEMS defines one way of doing things. This means integrated and consistent standards, processes and procedures that reduce risk and enable continuous improvement. By following consistent standards and streamlining processes, Suncor expects to benefit from improved reliability and associated lower costs. OEMS is raising Suncor's focus on the management of risk for our people, communities, the environment and our assets.

There are three main purposes for OEMS:

- ensure compliance with all legal requirements and commitments;
- adequately manage and control risk; and
- apply a continuous improvement mindset to operational performance and sustain it.

OEMS has the ultimate goal of guiding operational excellence. Suncor's process safety work – which began in 2009 to bring early focus to addressing process safety hazards – and Suncor's enterprise risk management system are both in alignment with OEMS.

The first step in the implementation of OEMS is to examine Suncor's various systems, standards, processes and procedures and how well they are being followed. This information is compared to OEMS requirements, which provides one consistent measuring stick for the entire organization. This process is called the baseline self-assessment. During 2011, the majority of organizational units underwent this assessment to identify strengths in Suncor's performance and gaps where there is potential for increased risk.

In 2012, Suncor successfully completed baseline self-assessments and prioritized the gaps identified based on risk. Gap closure is currently underway, and Suncor is focused on executing in such a way as to enhance efficiency and reliability, through effective collaboration.

OEMS is a cyclical process. Work across the organization is planned, completed, checked for compliance against OEMS and adjustments made to continually address any identified gaps in performance and drive continuous improvement.

OUR SCORECARD

Our scorecard should be read in conjunction with Suncor's 2012 MD&A, and the 2012 audited Consolidated Financial Statements and accompanying notes.

2012: Our Goals and How We Delivered

Goals for 2012 are as expressed in Suncor's 2011 Annual Report.

Suncor continues to be well positioned to address business opportunities and challenges created by changing market conditions, as well as to take advantage of opportunities to develop an impressive suite of growth projects. The company's financial strength is bolstered by its integrated business model, which increases profitability throughout the value chain. A relentless focus on operational excellence is leading to improvements in reliability, while prudent capital discipline continues to increase project returns. Suncor also continues to make progress on its publicly announced 2015 environmental performance goals. The following summarizes how Suncor's business strategy is delivering results for shareholders.

Continue process improvement across all Suncor operations with a focus on safety, environment, reliability, and people

- A focus on operational excellence helped Suncor achieve record Oil Sands production of 359,200 bbls/d in 2012 compared to 339,300 bbls/d in 2011. At the same time, Suncor's integrated business model enabled the Refining and Marketing business unit to achieve record margins and industry leading returns. Reliability was instrumental in achieving these results as evidenced by a 95% utilization rate at the company's refineries, leading to nameplate capacity increases for three out of four of Suncor's refineries over the past year. The year was not without its challenges as Suncor's production was impacted by upgrader reliability in Oil Sands and difficulties reconnecting subsea infrastructure following dockside maintenance at Terra Nova. Measures to improve upgrader reliability will continue in 2013.

- The company continued the enterprise-wide implementation of its OEMS, which in 2012 saw the completion of business unit baseline self-assessments. Safety performance showed measurable improvement, while environmental performance, as measured by releases, non-compliances, and freshwater consumption, also improved. On the people front, Suncor continued to demonstrate strong performance in reducing attrition and improving the quality of robust career and development planning throughout the company.

Rigorous cost control in our Oil Sands operations

- Suncor made significant progress in driving down costs at its Oil Sands operations, despite incurring costs associated with the ramp up of new facilities at Firebag. Oil Sands cash costs per barrel of $37.05 for 2012 were at the lower end of our target, and decreased by $2/bbl compared to the prior year. A relentless focus on reliability will continue to be a key element in controlling costs at the company's Oil Sands operations.

Steadily increasing production at Firebag

- Suncor successfully grew production by 75% at its Firebag operations, with the ramp up of Firebag Stage 3 and commissioning of Firebag Stage 4 facilities in 2012. Average bitumen production from Firebag increased to 104,000 bbls/d in 2012 from 59,500 bbls/d in 2011. The company successfully commissioned the Stage 4 cogeneration units and central processing facilities ahead of schedule, and achieved first oil before the end of 2012. Production from the Firebag complex is expected to grow throughout 2013 and reach its capacity of 180,000 bbls/d over the next year.

Superb execution of our capital projects

- With a strong suite of growth projects, Suncor continues to be well positioned for the future. In 2012, senior leadership reviewed the company's long-term strategy, which led to a renewed focus on capital discipline. Prioritizing cost and quality over schedule has helped to deliver profitable growth and drive long-term shareholder value.

Demonstrated capability to drive value through strategic arrangements

- In 2012, the Oil Sands Ventures business unit continued to build organizational capacity and expertise in order to progress work on major oil sands initiatives. Significant effort was dedicated to optimizing project designs and leveraging OEMS to advance projects from concept to development and management. The changing North American crude oil market led to a rigorous review of the projects to ensure they remained aligned with

Suncor's long-term strategy and on track to deliver acceptable levels of return on investment. As part of these reviews, Suncor and its co-owner committed to reaching a decision on the Voyageur upgrader project by the end of the first quarter of 2013. During the year, Suncor and its co-owner continued to progress development of the Golden Eagle project, on track to achieve first oil in late 2014 or early 2015, and also sanctioned the Hebron project.

2013: Our Targets and How We Will Get There

Continue to advance Suncor's journey to Operational Excellence

- Building on progress already achieved in 2012, Suncor will continue its multi-year journey towards safe, reliable and world-class operations. The company continues to instil a culture which encourages operational discipline and collaboration amongst employees and partners. As part of the company's commitment to personal and process safety, Suncor will also seek further improvements in these key operational excellence metrics. Vital to these efforts will be continued implementation of OEMS, which is aimed at driving improvements in key business processes. The company will also focus on strengthening governance standards and measures to support and sustain performance.
- In further support of operational excellence, Suncor mobilized a process improvement team in 2012 to work with business units and functions to execute a company-wide initiative to integrate and simplify processes, information and systems.

Improve maintenance and reliability across Suncor's operations

- Suncor recognizes that an important factor in achieving operational excellence is improved maintenance and reliability across its operations. The company will continue its efforts to implement technology and productivity initiatives to increase production, while driving down costs – both considered essential to Suncor's profitability. A focus on oil sands reliability, specifically targeted at the company's upgrading assets, will be key to driving improved operational performance. This effort, combined with ongoing initiatives to reduce Suncor's operational risk profile, we expect will effectively position the company to consistently deliver strong results.

Attract and engage employees in support of Suncor's business strategy

- Implementation of Suncor's business strategy will continue to require the attraction, onboarding and retention of a skilled workforce. By leveraging our refreshed vision, mission and value statements that we launched in late 2012, we will engage employees in delivering on Suncor's business strategy. Our efforts will be supported by a robust goal alignment process, designed to drive performance and collaboration across all areas of the company. We will also continue to build talent within the organization, implementing employee competency and skill development programs to drive productivity and employee engagement in support of Suncor's business objectives.

Generate and sustain industry leading returns

- Changing market conditions, an increasingly competitive environment, and heightened shareholder expectations are key challenges facing Suncor and its industry peers. The company's long-term strategy includes profitably operating and developing its oil sands resources, optimizing value through integration of assets and driving down costs. We will continue to focus on achieving operational and reliability improvements at existing facilities as well as exercising capital discipline on new projects in order to deliver profitable growth. Additionally, the advancement of various debottlenecking projects in 2013 is expected to provide future cost efficiencies and higher returns. Monitoring of key metrics, including ROCE, total shareholder return, annual growth, operating reliability and cost targets will guide our efforts. Delivering cash to shareholders through dividends and share repurchases will also continue to be a financial priority for the company.

Achieve long-term sustainability targets

- Suncor will continue to seek performance improvements in order to achieve publicly announced 2015 environmental goals on air emissions, water withdrawals, land reclamation and energy efficiency. Through consultation with stakeholders, Suncor has commenced the planning of goals for the post-2015 period. Recognizing the importance of environmental collaboration, Suncor will maintain a leadership role in industry, liaising with other companies through the Oil Sands CEO Council, and COSIA. Suncor will also continue to engage with Aboriginal communities in various areas, including ensuring mutual benefits from industry development.

2013 CORPORATE GUIDANCE

The following table provides highlights from Suncor's 2013 Full Year Outlook and actual results for the year ended December 31, 2012. For further details regarding Suncor's 2013 Full Year Outlook, see www.suncor.com/guidance.

	Actual Year Ended December 31, 2012	**2013 Full Year Outlook February 5, 2013**
Oil Sands (bbls/d)	324,800	**350,000 - 380,000**
Syncrude (bbls/d)	34,400	**34,000 - 38,000**
North America Onshore (boe/d)	53,900	**41,000 - 46,000**
East Coast Canada (bbls/d)	46,500	**55,000 - 60,000**
International (boe/d)	89,500	**90,000 - 96,000**
Suncor Total Production (boe/d)	549,100	**570,000 - 620,000**
Suncor Refinery Throughputs		
Eastern North America (bbls/d)	197,600	**185,000 - 205,000**
Western North America (bbls/d)	233,700	**215,000 - 235,000**
Suncor Refinery Utilization (1)		
Eastern North America	89%	**83% - 92%**
Western North America	100%	**91% - 100%**

(1) Refinery utilizations for 2012 are based on the following crude processing capacities: Montreal – 137,000 bbls/d; Sarnia – 85,000 bbls/d; Edmonton – 135,000 bbls/d; and Commerce City – 98,000 bbls/d. Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery to 140,000 bbls/d.

For Oil Sands operations, Suncor anticipates average production between 350,000 bbls/d and 380,000 bbls/d for 2013. This increase from 2012 assumes higher production from Firebag bitumen operations and higher reliability from upgrading assets. This forecast includes the impacts of a seven-week planned maintenance event at Upgrader 1 in the second quarter of 2013 and the refurbishment of the hydrogen plant at Upgrader 1, which is expected to be offline for approximately 14 weeks commencing in the first quarter.

For Syncrude, Suncor anticipates its share of production will average between 34,000 bbls/d and 38,000 bbls/d, consistent with 2012 rates.

For North America Onshore, Suncor anticipates average production between 41,000 boe/d and 46,000 boe/d in 2013, which is lower than 2012 due primarily to natural declines in reservoir performance and wells that were the shut in during the first half of 2012.

For East Coast Canada, Suncor anticipates average production between 55,000 bbls/d and 60,000 bbls/d, which is higher than 2012 due primarily to significant planned maintenance programs at Terra Nova and White Rose in 2012.

For International, Suncor anticipates average production between 90,000 boe/d and 96,000 boe/d, which is slightly higher than 2012 and assumes stabilized production in Libya and continued improved reliability at Buzzard, following the planned maintenance program in 2012. The company's outlook for International includes no production from Syria.

Refinery throughputs and utilization are consistent with 2012 results; however, the 2013 ranges for throughput reflect the impact of larger scope planned maintenance activities in 2013, and the 2013 ranges for utilization reflect the higher nameplate capacity of the Edmonton refinery.

Capital Expenditures (1)(2)

2013 Full Year Outlook February 5, 2013 ($ millions)	Sustaining	Growth	Total
Oil Sands	2 960	1 235	4 195
Oil Sands	*2 540*	*570*	*3 110*
Oil Sands Ventures	*420*	*665*	*1 085*
Exploration and Production	205	1 640	1 845
Refining and Marketing	670	60	730
Corporate, Energy Trading and Eliminations	155	375	530
	3 990	**3 310**	**7 300**

(1) Capital expenditures exclude capitalized interest of $450 million to $550 million.

(2) For definitions of sustaining and growth capital expenditures, see the Capital Investment Update section of the MD&A. Capital expenditures attributed to Corporate, Energy Trading and Eliminations include a $250 million growth capital pool to be allocated to the company's segments at the discretion of management.

Advisories

The Our Scorecard and 2013 Corporate Guidance sections above contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond Suncor's control, including those outlined below. See also the Forward-Looking Information section of the MD&A for the additional risks and assumptions underlying this forward-looking information.

Suncor's corporate guidance is based on the following assumptions around oil prices: WTI, Cushing of US$85.00/bbl; Brent, Sullom Voe of US$97.00/bbl; and WCS, Hardisty of US$65.00/bbl. In addition, the guidance is based on the assumption of a natural gas price (AECO – C Spot) of Cdn$3/GJ and an exchange rate (US$/Cdn$) of $0.97. Assumptions for the Oil Sands and Syncrude 2013 production outlook include those relating to reliability and operational efficiency initiatives that we expect will minimize unplanned maintenance in 2013. Assumptions for the East Coast Canada and International 2013 production outlook include those relating to reservoir performance, drilling results and facility reliability. Factors that could potentially impact Suncor's 2013 corporate guidance include, but are not limited to:

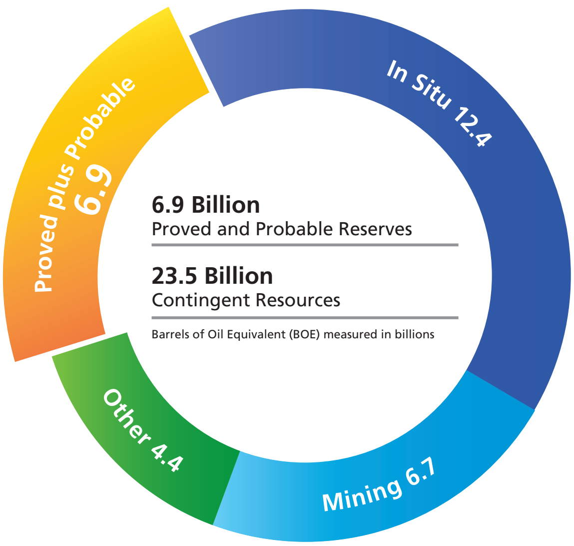
- *Bitumen supply. Bitumen supply may be dependent on unplanned maintenance of mine equipment and extraction plants, bitumen ore grade quality, tailings storage and in situ reservoir performance.*
- *Availability of infrastructure. A number of new storage and distribution infrastructure projects are currently planned or in progress, which we expect will support growth at Oil Sands operations. The timing for the completion and successful integration of these projects into existing operations may impact production, much of which is out of the company's direct control.*
- *Performance of recently commissioned facilities or well pads. Production rates while new equipment is being brought into service are difficult to predict and can be impacted by unplanned maintenance. Sweet SCO production levels from Oil Sands are dependent on the successful operation of the Millennium Naphtha Unit (MNU). Bitumen production levels are dependent on the successful ramp up of Firebag Stage 4.*
- *Unplanned maintenance. Production estimates could be negatively impacted if unplanned work is required at any of our mining, extraction, upgrading, in situ processing, refining, natural gas processing, pipeline, or offshore assets.*
- *Planned maintenance events. Production estimates, including production mix, could be negatively impacted if planned maintenance events are affected by unexpected events.*
- *Commodity prices. Declines in commodity prices may alter our production outlook and/or reduce our capital expenditure plans.*
- *Foreign operations. Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks.*

RESERVES AND RESOURCES SUMMARY

With a significant reserves and resources base, Suncor is well positioned, not only to sustain current production but also to capitalize on a suite of future growth opportunities. Suncor has approximately 6.9 billion boe of proved and probable reserves, with the reserves base for SCO and bitumen being the largest in Oil Sands[1]. Suncor's high quality in situ reserves and resources are expected to enable the company to sustain its position as a leader in in situ production.

Summary of Gross Proved and Probable Reserves[2]

As at December 31, 2012 (forecast prices and costs)	Proved	Probable	Proved Plus Probable
SCO (mmbbls)			
Gross	2 623	1 599	4 222
Net	2 298	1 342	3 640
Bitumen (mmbbls)			
Gross	964	695	1 659
Net	836	552	1 388
Light & Medium Oil (mmbbls)			
Gross	362	432	794
Net	243	290	533
Natural Gas (bcf)			
Gross	859	269	1 128
Net	745	222	967
NGLs (mmbbls)			
Gross	8	3	11
Net	6	2	8
Total (mmboe)			
Gross	**4 099**	**2 775**	**6 874**
Net	**3 507**	**2 222**	**5 729**



Reconciliation of Gross Proved and Probable Reserves[2][3]

(forecast prices and costs)	SCO (mmbbls)	Bitumen (mmbbls)	Light & Medium Oil (mmbbls)	Natural Gas[4] (bcf)	NGLs (mmbbls)	Total (mmbbls)
December 31, 2011	4 552	1 403	782	1 995	36	7 106
Extensions and improved recoveries	20	13	15	10	—	50
Technical revisions	(236)	261	45	(685)	(24)	(68)
Discoveries	—	—	2	—	—	2
Dispositions	—	—	—	—	—	—
Economic factors	—	—	—	(87)	—	(15)
Production	(114)	(18)	(50)	(105)	(1)	(201)
December 31, 2012	4 222	1 659	794	1 128	11	6 874

(1) As at December 31, 2011 and based on Sproule Canadian Oil & Gas Reserves 2011 Chart.

(2) Gross refers to Suncor's working interest (operated and non-operated) share before deduction of royalties and without including the company's royalty interests in reserves; net refers to Suncor's working interest (operated and non-operated) share after deduction of royalties, plus the company's royalty interests in reserves.

(3) Extensions and improved recoveries are additions to the reserves resulting from step-out drilling, infill drilling and implementation of improved recovery schemes. Discoveries are additions to reserves in reservoirs where no reserves were previously booked. Technical revisions include changes in previous estimates; upward or downward, resulting from new technical data or revised interpretations. Technical revisions in 2012 include reserves related to Syria that were reclassified to contingent resources. Economic factors are changes due primarily to price forecasts, inflation rates or regulatory changes.

(4) Includes associated and non-associated gas (combined).

Net Present Value of Future Net Revenues Before Income Taxes

Proved plus probable reserves (forecast prices and costs, in $ millions, discounted at % per year)	0%	5%	10%	15%	20%
Mining	64 199	34 229	22 108	16 055	12 577
In Situ	89 673	32 797	16 033	9 534	6 422
East Coast Canada	17 002	10 996	7 815	5 931	4 719
International	22 199	15 961	12 389	10 123	8 574
North America Onshore	3 818	2 452	1 795	1 415	1 168
Total as at December 31, 2012	196 891	96 435	60 140	43 058	33 460
Total as at December 31, 2011	245 084	120 302	74 255	52 416	40 161

Best Estimate Gross Contingent Resources (1)(2)

(forecast prices and costs)	SCO (mmbbls)	Bitumen (mmbbls)	Light & Medium Oil (mmbbls)	Natural Gas (bcf)	NGLs (mmbbls)	Total (mmboe)
Mining	4 582	2 112	—	—	—	6 694
In Situ	6 419	5 997	—	—	—	12 416
East Coast Canada	—	—	250	2 679	—	696
International	—	—	474	1 500	27	751
North America Onshore	—	—	35	16 026	223	2 929
December 31, 2012	11 001	8 109	759	20 205	250	23 486
December 31, 2011	11 014	8 176	889	10 634	14	21 865

(1) Contingent resources are those quantities of petroleum 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 recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or lack of infrastructure or markets. There is no certainty that it will be commercially viable to produce any of the contingent resources. Gross refers to Suncor's working interest (operated and non-operated) share before deduction of royalties and without including the company's royalty interest in contingent resources. Best Estimate contingent resources are considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production.

(2) Figures represent Suncor's Best Estimate of contingent resources, effective December 31, 2012, with the exception of International and North America Onshore. International includes contingent resources for Syria, which were previously classified as reserves as at December 31, 2011, based on a reserves evaluation prepared by Sproule with an effective date of December 31, 2011. These reserves have been reclassified as contingent resources as a result of Suncor's suspension of operations in Syria and the resources have an effective date of December 31, 2011. North America Onshore includes contingent resources for the Montney shale formation of northeast B.C., which is based on an independent assessment conducted by Sproule Unconventional Limited as at June 30, 2012. The contingent resources associated with this formation include 7,358 bcf of Natural Gas and 197 mmbbls of NGLs.

Suncor's proved reserves as at December 31, 2012 increased approximately 2% from December 31, 2011 and approximately 9% after adjusting for 2012 production and the impacts of the reclassification of all Syria reserves to contingent resources. Increases in proved reserves were primarily due to new well pad applications and infill wells at Firebag, extension of the project area at MacKay River, and the extension of the approved mining limit for the North Steepbank area.

Suncor's proved plus probable reserves as at December 31, 2012 decreased approximately 3% from December 31, 2011, but increased approximately 2% after adjusting for 2012 production and the impacts of the reclassification of all Syria reserves to contingent resources. Increases in proved plus probable reserves were due mainly to technical revisions for numerous assets and extensions for Firebag and Libya.

The net present value of future net revenues (10% discount before tax) for Suncor's proved plus probable reserves decreased from $74.3 billion in 2011 to $60.1 billion in 2012. The decline was due primarily to significantly lower price forecasts in 2012 compared to 2011. Forecasted prices for WTI, the light/heavy differential and the differential for SCO relative to WTI changed unfavourably from prior year forecasts, resulting in a decline in the net present value of Oil Sands proved plus probable reserves. While the forecasted prices reflect discounting of inland crudes, the corresponding benefit to Suncor's refining operations is not reflected in the net present value calculations shown above. The 2012 net present values were also impacted by lower international reserves volumes due to the transfer of Syria natural gas volumes from reserves to contingent resources, offset by an increase in reserves relating to Firebag and Libya, discussed above.

Contingent resources increased approximately 7% to 23,486 mmboe at December 31, 2012, due mainly to the recognition of natural gas and NGL resources associated with Suncor's properties in the Montney formation and the reclassification of all reserves associated with Syria to contingent resources due to political unrest and international sanctions against the country.

Advisories to Reserves and Resources Summary Tables

Reserves data summarizes Suncor's SCO, bitumen, light and medium oil, NGL and natural gas reserves and the net present values of future net revenues for these reserves using forecast prices and costs and was prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. For more information regarding our reserves and resources disclosure, please see the Statement of Reserves Data and Other Oil and Gas Information in Suncor's Annual Information Form dated March 1, 2013 (the 2012 AIF), which statement is incorporated by reference herein. The reserves data are based on evaluations by GLJ Petroleum Consultants Ltd. (GLJ), Sproule Associates Limited and Sproule International Limited, our independent qualified reserves evaluators, which were all completed with an effective date of December 31, 2012.

The SCO, bitumen, oil, NGLs and natural gas reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Estimates of net present value for future net revenues do not represent fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. International reserves, which include Libya, include quantities of crude oil, NGLs and natural gas reserves that will be produced under Exploration and Production Sharing Agreements that involve the company in upstream risks and rewards, but do not transfer title of the production to the company.

GLJ conducted an independent assessment of Best Estimate contingent resources volumes for all of Suncor's Mining properties and its Firebag and Steepbank In Situ properties. For remaining In Situ properties, including MacKay River, GLJ audited assessments of Best Estimate contingent resources volumes (approximately 48% of In Situ contingent resources) prepared by Suncor's internal qualified reserves evaluators. Sproule Unconventional Limited conducted an independent assessment of Suncor's Best Estimate contingent resources in the Montney shale formation of northeast B.C., as at June 30, 2012. Best Estimate contingent resources for remaining conventional properties were prepared by Suncor's internal qualified reserves evaluators without independent audit or review. All contingent resources estimates were conducted in accordance with the Canadian Oil and Gas Evaluation (COGE) Handbook. The effective date of Suncor's best estimate of contingent resources is as of December 31, 2012, except in the case of the Montney shale formation of northeast B.C., which is as at June 30, 2012 and in the case of Syria, which is as at December 31, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 26, 2013

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2012 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated March 1, 2013 (the 2012 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website, www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A, and is not incorporated into this MD&A by reference.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context requires otherwise.

MD&A – Table of Contents

1. ADVISORIES

Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within Part 1 of the Canadian Institute of Chartered Accountants Handbook, which itself is within the framework of International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working interest basis, before royalties, unless otherwise noted. Certain prior year amounts in the Consolidated Statements of Comprehensive Income have been reclassified to conform to the current year's presentation.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings and Oil Sands cash operating costs are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A. Cash flow from operations and ROCE are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of this MD&A.

These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement	
bbl	barrel
bbls/d	barrels per day
mbbls/d or kbpd	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
m^3/d	cubic metres per day
MW	megawatts

Places and Currencies	
U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment	
DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil
NYMEX	New York Mercantile Exchange

Risk Factors and Forward-Looking Information

The company's financial and operational performance is potentially affected by a number of factors, including, but not limited to, the volatility of commodity prices and exchange rate fluctuations; government regulation, including changes to royalty and income tax legislation and the interpretation and implementation thereof; environmental regulation, including changes to climate change and reclamation legislation; risks associated with operating in foreign countries, including geopolitical and other political risks; operating hazards and other uncertainties, including extreme weather conditions, fires, explosions and oil spills; risks associated with the execution of major projects; reputational risk; permit approval; labour and materials supply; and other issues described within the Advisory – Forward-Looking Information section of this MD&A.

This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information.

Measurement Conversions

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, conversion on a 6:1 basis may be misleading as an indication of value.

2. 2012 HIGHLIGHTS

- **Suncor reports strong operating earnings and cash flow from operations.**
  - Net earnings for 2012 were $2.783 billion, compared to $4.304 billion in 2011.
  - Operating earnings[(1)] for 2012 were $4.890 billion, compared to $5.674 billion in 2011.
  - Cash flow from operations[(1)] for 2012 was $9.745 billion, compared to $9.746 billion in 2011.
  - ROCE[(1)] (excluding major projects in progress) was 7.3% for the twelve months ended December 31, 2012, compared to 13.8% for the twelve months ended December 31, 2011. ROCE was impacted by approximately 4% due to an after-tax impairment of $1.487 billion for the Voyageur upgrader project.

- **Suncor's integrated business model translates low mid-continent crude oil prices to high refining margins.**

  The Refining and Marketing segment contributed over $3.1 billion to cash flow from operations in 2012 compared to $2.6 billion in 2011, reinforcing the value of an integrated business model to Suncor's consolidated results. Suncor's inland refineries benefited from discounts for mid-continent crude feedstock produced in our Oil Sands operations. Demonstrated reliability and continuous improvements of the company's refining facilities resulted in 95% overall refinery utilization in 2012, further contributing to the strength of Suncor's integrated model.

- **Suncor's balance sheet remains strong and primed for future growth.**

  Significant cash flow from the company's integrated and diverse operations and a disciplined approach to spending solidified Suncor's financial position.

  - Cash flow from operations for 2012 exceeded capital and exploration expenditures (including capitalized interest) by over $2.7 billion, and were higher than net debt at year end by $3.1 billion.
  - Net debt at December 31, 2012 was $6.6 billion, and decreased from $7.0 billion at December 31, 2011. Cash and cash equivalents at December 31, 2012 were $4.4 billion and increased from $3.8 billion at December 31, 2011.

- **Suncor returns cash to shareholders.**

  Suncor shareholders received over $2.2 billion in cash from the company during 2012 through share repurchases and dividends.

  - The company returned $1.5 billion to shareholders through the repurchase of 46.9 million common shares in 2012, at a weighted average price of $30.96 per share. The completion of the $1.5 billion share repurchase program that was initiated in 2011 and additional repurchases under the $1.0 billion program announced in 2012 resulted in a $1.0 billion increase in repurchases over the prior year.
  - The company increased its quarterly dividend by 18% to $0.13 per common share.

- **Bitumen production from Firebag increases by 75% resulting in record production for the Oil Sands.**

  Knowledge and expertise gained through previous Firebag construction phases were applied to Firebag Stage 4, resulting in timely execution, reliable operations and effective cost control.

  - Average production in 2012 increased to 104,000 bbls/d from 59,500 bbls/d in 2011. Suncor expects to approach production capacity of 180,000 bbls/d over the next year.
  - Cogeneration units for Stage 4 were completed ahead of schedule and steam injection for both well pads was in progress by the end of 2012. Stage 4 central processing facilities operated at 10% capacity throughout the fourth quarter, enabling the company to process incremental bitumen supply from Stage 3 wells and infill drilling projects.
  - Stage 4 was executed ahead of schedule and is expected to be approximately 15% below the announced cost estimate of $2.0 billion.

- **Execution of major capital projects adds value to Suncor.**
  - The company completed the Millennium Naphtha Unit (MNU) in 2012. The company expects that the MNU will increase sweet SCO production capacity by approximately 10% and stabilize secondary upgrading processes by providing flexibility during maintenance.
  - The company completed its tailings management (TRO_{TM}) project in 2012, which has set the foundation for Suncor's TRO_{TM} process. Through the TRO_{TM}

process, mature fine tailings are converted more rapidly into a solid landscape suitable for reclamation.

- The development of the North Steepbank mining area provided Suncor with access to a significant reserves base. The full ramp up of production from the North Steepbank mining area resulted in efficiencies through reduced mine congestion and lower average haul distances.

- **Suncor offers attractive prospects for long-term profitable growth.**

  In support of Suncor's capital discipline initiative, growth capital for 2013 is focused on high return projects, reflecting a balance between projects in the Oil Sands and Exploration and Production segments.

  - Suncor continues to focus on the optimization of assets and construction of infrastructure to enhance regional takeaway capacity and marketing flexibility of Oil Sands production. In support of these initiatives, the Wood Buffalo pipeline and two of four storage tanks at Hardisty, Alberta were commissioned in late 2012, and various debottlenecking projects in the Oil Sands operations are currently underway.
  - In the Exploration and Production segment, the company will continue to advance the Hebron and Golden Eagle Area Development (Golden Eagle) projects. In 2012, the company and the co-owners of Hebron announced project sanction. The estimated gross oil production capacity for Hebron is 150,000 bbls/d. First oil is targeted for late 2017.
  - Growth capital in Refining and Marketing will be focused on projects to prepare the Montreal refinery to receive shipments of western crude feedstock.

- **Suncor continues to evaluate a suite of growth opportunities.**

  - Suncor's Oil Sands Ventures business, dedicated to ensuring the success of Suncor's joint arrangements, continued to work closely with other owners on evaluating and progressing growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.
  - With a significant reserves and resources base, Suncor continues to assess potential in situ growth prospects at Firebag, MacKay River, Meadow Creek and Lewis.
  - Suncor continues to explore offshore prospects in Norway and the U.K. North Sea.

- **A continued focus on operational excellence and improved reliability.**

  - Demonstrated reliability and continuous improvements at Suncor's refineries resulted in nameplate capacity increases for three out of four refineries since 2011, and an overall refinery utilization rate of 95% for 2012.
  - Although 2012 was a challenging year in terms of reliability for upgrading facilities, Suncor's underlying cost discipline and performance trends were positive, as reflected in a $2/bbl decrease in cash operating costs(1) per barrel from $39.05 in 2011 to $37.05 for Suncor's Oil Sands operations in 2012. Suncor continued to work towards higher reliability in 2012 with the completion of planned maintenance on several coker units and hydrotreaters at Upgrader 1 and 2.
  - Suncor executed planned maintenance on all offshore producing assets in 2012, including the repair of the propulsion system at White Rose, and the replacement of the water injection swivel and subsea infrastructure at Terra Nova. Production at Terra Nova resumed from the largest drill centre in December 2012, while production from a second drill centre was delayed until February 2013. The third drill centre is expected to be commissioned in the third quarter of 2013.

- **Operations resumed in Libya, but remained suspended in Syria.**

  - Subsequent to the successful restart of production in late 2011, average production from Libya exceeded 40,000 boe/d. In 2013, Suncor plans to continue the redevelopment of existing fields and resume exploration activities.
  - As a result of the political unrest that began in Syria in the latter half of 2011 and ensuing international sanctions, Suncor declared force majeure under its contractual obligations and suspended operations in the country in December 2011. The company has ceased recording all production and revenue and continues to comply with all applicable sanctions. Suncor received $300 million in risk mitigation proceeds in 2012, which are subject to a provisional repayment should operations resume in Syria.

- **Suncor continues to invest in renewable energy assets.**

  The company continues to progress the Adelaide and Cedar Point wind projects through the regulatory process in 2013. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

(1) Operating earnings, cash flow from operations, ROCE and Oil Sands cash operating costs are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

3. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. We are strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas in Canada and internationally, and we transport and refine crude oil, and market petroleum and petrochemical products primarily in Canada. Periodically, we market third-party petroleum products. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Wood Buffalo region of northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into SCO for refinery feedstock and diesel fuel. The Oil Sands segment includes:

- **Oil Sands** operations refer to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands. Oil Sands operations consist of:
  - **Oil Sands Base** operations include the Millennium and North Steepbank mining and extraction operations, integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets – including utilities, energy and reclamation facilities, such as Suncor's tailings management (TRO_{TM}) assets.
  - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities and cogeneration units. In Situ production is either upgraded by Oil Sands Base or blended with diluent and marketed directly to customers.
- **Oil Sands Ventures** assets include the company's interests in significant growth projects, including its 36.75% interest in the Joslyn North mining project, and two projects where Suncor is the operator, including its 40.8% interest in the Fort Hills mining project and its 51.0% interest in the Voyageur upgrader project. Oil Sands Ventures also includes the company's 12.0% interest in the Syncrude oil sands mining and upgrading operation.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

- **East Coast Canada** operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds a 20.0% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.
- **International** operations include Suncor's 29.89% working interest in Buzzard and its 26.69% interest in Golden Eagle, both in the U.K. sector of the North Sea and both of which are not operated by Suncor. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Suncor also owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Due to unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely.
- **North America Onshore** operations include Suncor's interests in a number of natural gas and conventional crude oil assets, primarily in Western Canada.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

- **Refining and Product Supply** operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Québec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado. Other Refining and Product Supply assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.
- Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include six operating wind power projects across Canada, two wind power projects under development in Ontario, and the St. Clair ethanol plant in Ontario.
- **Energy Trading** activities primarily involve the marketing, supply and trading of crude oil, natural gas and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.
- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.
- Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

4. CONSOLIDATED FINANCIAL INFORMATION

Financial Highlights

Year ended December 31 ($ millions, except per share amounts)	**2012**	2011	2010
Net earnings	**2 783**	4 304	3 829
per common share – basic	**1.80**	2.74	2.45
per common share – diluted	**1.79**	2.67	2.43
Operating earnings (1)	**4 890**	5 674	2 634
per common share – basic	**3.17**	3.61	1.69
Cash flow from operations (1)	**9 745**	9 746	6 656
per common share – basic	**6.31**	6.20	4.25
Dividends on common shares (2)	**756**	664	611
per common share – basic	**0.50**	0.43	0.40
Operating revenues, net of royalties (3)	**38 208**	38 339	31 315
ROCE (1)(4) (%)			
For the twelve months ended	**7.3**	13.8	11.4
Balance Sheet			
Total assets	**76 449**	74 777	68 607
Long-term debt (5)	**10 249**	10 016	10 347
Net debt	**6 632**	6 976	11 254

Segment Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss)			
Oil Sands	**458**	2 603	1 520
Exploration and Production	**138**	306	1 938
Refining and Marketing	**2 129**	1 726	819
Corporate, Energy Trading and Eliminations	**58**	(331)	(448)
Total	**2 783**	4 304	3 829
Operating earnings (loss) (1)			
Oil Sands	**2 015**	2 737	1 379
Exploration and Production	**850**	1 358	1 193
Refining and Marketing	**2 144**	1 726	796
Corporate, Energy Trading and Eliminations	**(119)**	(147)	(734)
Total	**4 890**	5 674	2 634
Cash flow from operations (1)			
Oil Sands	**4 407**	4 572	2 777
Exploration and Production	**2 227**	2 846	3 325
Refining and Marketing	**3 150**	2 574	1 538
Corporate, Energy Trading and Eliminations	**(39)**	(246)	(984)
Total	**9 745**	9 746	6 656

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Dividends paid on common shares does not include a value for common share dividends granted under the company's dividend reinvestment program.

(3) The company has reclassified prior year operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(4) Excludes capitalized costs related to major projects in progress.

(5) Includes current portion of long-term debt.

Operating Highlights

Year ended December 31	2012	2011	2010
Production Volumes (mboe/d)			
Oil Sands	**359.2**	339.3	318.2
Exploration and Production	**189.9**	206.7	296.9
	549.1	546.0	615.1
Price Realizations ($/boe)			
Oil Sands	**82.75**	90.07	70.85
Exploration and Production	**84.05**	79.95	61.06
	83.20	86.23	66.12
Refinery Utilization [(1)(2)] (%)			
Eastern North America	**89**	94	89
Western North America	**100**	91	95
	95	92	92

(1) Effective January 1, 2012, the company increased the nameplate capacity of the Montreal refinery from 130,000 bbls/d to 137,000 bbls/d and the nameplate capacity of the Commerce City refinery from 93,000 bbls/d to 98,000 bbls/d. Prior years' utilization rates have not been recalculated and reflect the lower nameplate capacities. Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d to 140,000 bbls/d. Figures above have not been recalculated to reflect the revised nameplate capacity.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Production volumes for 2012 increased relative to 2011. Suncor achieved average production in the Oil Sands segment of 359,200 bbls/d in 2012 compared to 339,300 bbls/d in 2011. The increase was due primarily to the ramp up of production from Firebag, partially offset by the impact of constrained upgrader availability on mine production, due to planned and unplanned maintenance in 2012.

Production in the Exploration and Production segment was lower in 2012 compared with 2011 due to planned maintenance activities, the suspension of operations in Syria due to political unrest and international sanctions, and the shut in of natural gas wells in 2012 in response to low North American natural gas prices. This was partially offset by the resumption of production in Libya.

Net Earnings

Suncor's net earnings for 2012 were $2.783 billion, compared to $4.304 billion in 2011. Net earnings were affected by the same factors that influenced operating earnings, which are described in this section of the MD&A under the heading Operating Earnings. Other items affecting changes in net earnings in 2012, compared with 2011, included:

Operating Earnings Adjustments

- The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated long-term debt was $157 million in 2012, compared with a loss of $161 million in 2011.
- In 2012, the company recorded after-tax impairments (net of reversals), write-offs and provisions of $2.176 billion. Given Suncor's view of the challenging economic outlook for the Voyageur upgrader project, at December 31, 2012, Suncor performed an impairment test. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion. Due to political unrest and international sanctions against Syria, Suncor recorded an after-tax impairment (net of reversals) and write-offs for assets in Syria of $517 million. Additional impairments in 2012 included after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore, and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity.
- In 2012, the Province of Ontario approved a budget that froze the general corporate income tax rate at 11.5%, instead of the planned reduction to 10% by 2014. As a result, the company adjusted its deferred income tax balances leading to a one-time negative adjustment to net earnings of $88 million.
- In 2011, the company recorded net impairment charges of $503 million against assets pertaining to its operations in Libya, which were shut in as a result of political unrest. In 2011, the company also recorded $68 million of after-tax impairment charges against certain North America Onshore assets due to decreasing natural gas prices and after-tax write-offs of crude inventories of $58 million due primarily to third-party pipeline adjustments.

- In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the effective tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and to 62% in future years. As a result, the company revalued its deferred income tax balances, resulting in an increase to deferred income tax expense of $442 million.
- In 2011, the company disposed of assets resulting in after-tax losses of $107 million, consisting of $99 million on the partial disposition of interests in the Voyageur upgrader and Fort Hills projects, and $8 million for the sale of non-core Exploration and Production assets.
- In 2011, Suncor recorded an after-tax provision of $31 million in the Exploration and Production segment related to a royalty dispute concerning the deductibility of certain costs for a period before the merger with Petro-Canada.

Operating Earnings

Consolidated Operating Earnings Reconciliation (1)

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**2 783**	4 304	3 829
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)
Impairments (net of reversals), write-offs, and provisions	**2 176**	629	306
Impact of income tax rate adjustments on deferred income taxes	**88**	442	—
Loss (gain) on significant disposals (2)	**—**	107	(826)
Adjustments to provisions for assets acquired through the merger (3)	**—**	31	68
Change in fair value of commodity derivatives used for risk management, net of realizations (4)	**—**	—	(233)
Redetermination of working interest in Terra Nova (5)	**—**	—	(166)
Modification of the bitumen valuation methodology (6)	**—**	—	(51)
Merger and integration costs	**—**	—	79
Operating earnings (1)	**4 890**	5 674	2 634

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) In 2010, the company sold several Exploration and Production assets, including non-core assets in North America Onshore and the U.K. and those in the Netherlands and Trinidad and Tobago, and realized after-tax gains on the disposals of $826 million.

(3) Adjustments in 2010 were for pipeline commitments that the company determined to be unfavourable as a result of certain non-core North America Onshore asset dispositions, the write-off of certain unproven properties in the Exploration and Production segment, changes in the provision for the cancellation of the Montreal refinery coker project, a dry hole in Libya, and other cost estimates associated with the transition to EPSAs in Libya.

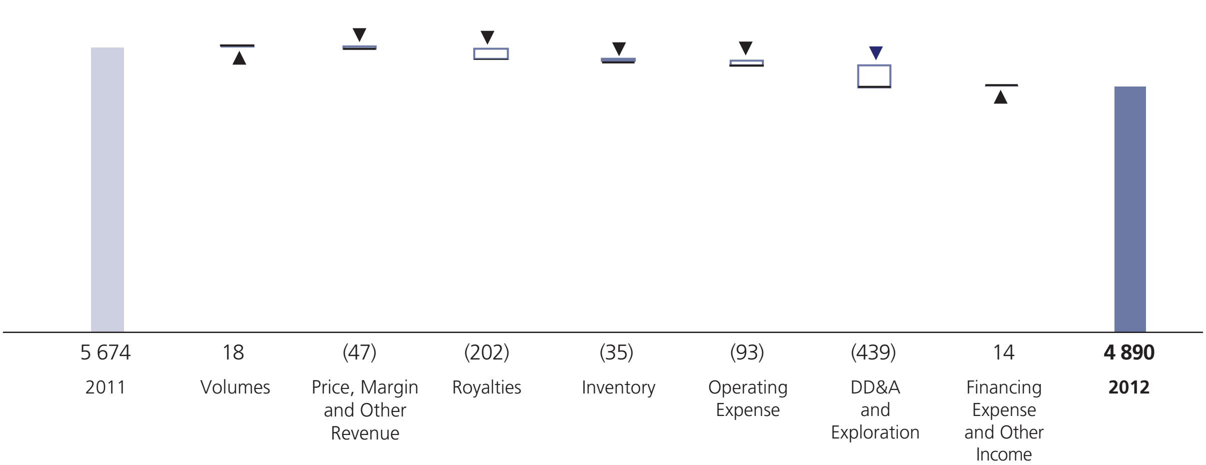
(4) Adjustments in 2010 represent the change in fair value of significant crude oil risk management derivatives, net of realized gains and losses recognized on the final settlement of those derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings.

(5) In 2010, Suncor recognized an after-tax gain of $166 million for the redetermination of its working interest in the Terra Nova oilfield, upon which the co-owners of Terra Nova reached agreement on a technical review of interests they contributed.

(6) In 2010, Suncor recognized a favourable royalty recovery related to modifications made by the Alberta government to the Bitumen Valuation Methodology (BVM) calculation applicable to Suncor for the interim period from January 1, 2009 to December 31, 2010.

Bridge Analysis of Consolidated Operating Earnings[1]

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Suncor's consolidated operating earnings for 2012 were $4.890 billion, compared to $5.674 billion in 2011. Factors that reduced operating earnings in 2012, compared to 2011, included:

- Production volumes from the Exploration and Production segment were lower in 2012, due primarily to planned off-station maintenance programs at Terra Nova and subsequent delays in reconnecting flow lines, planned maintenance at White Rose, the suspension of operations in Syria, and declines in production in North America Onshore, partially offset by the resumption of operations in Libya.
- Average price realizations for production from Oil Sands operations were lower in 2012, due primarily to lower premiums for sweet SCO relative to WTI, and wider light/heavy differentials that impacted prices for sour SCO and bitumen.
- Royalties were higher in 2012, compared with 2011, due primarily to higher production from Libya, where effective royalty rates are substantially higher than those for other Exploration and Production assets.
- The Inventory variance factor was negative, primarily due to an inventory build in Oil Sands in 2012 to fill new logistics infrastructure, including the Wood Buffalo pipeline and storage tanks in Hardisty, Alberta.
- Operating expenses increased due primarily to an increase in share-based compensation expense of $353 million in 2012 compared to 2011, as a result of an increase in the company's common share price from December 31, 2011 to December 31, 2012.
- DD&A and exploration expenses were higher in 2012 relative to 2011 due primarily to a larger asset base as a result of assets commissioned in 2012 and late 2011, higher exploration write-offs, partially offset by less DD&A expense related to lower production in the Exploration and Production segment.
- Operating earnings for International assets were also negatively impacted by a higher effective tax rate in the U.K.

The following factors had a positive impact on operating earnings in 2012 compared to 2011:

- Production volumes in the Oil Sands segment increased to 359,200 bbls/d in 2012 from 339,300 bbls/d in 2011, primarily due to the ramp up of Firebag production.
- Refining and marketing achieved record operating earnings in 2012 and absorbed much of the negative impact that low synthetic and heavy crude pricing had on the Oil Sands segment. Refining margins were higher in 2012 due to lower feedstock costs and higher crack spreads compared to 2011 and continued reliability from the company's refineries.

Cash Flow from Operations

Consolidated cash flow from operations for 2012 was $9.745 billion, compared to $9.746 billion in 2011. Cash flow from operations was impacted by lower price realizations in the Oil Sands segment, partially offset by strong refining margins. Lower production in the Exploration and Production segment was offset by the increase in the production from the Oil Sands segment.

Results for 2011 compared with 2010

Net earnings for 2011 were $4.304 billion compared to $3.829 billion in 2010. The increase in net earnings was due mainly to the same factors impacting operating earnings, partially offset by the operating earnings adjustments described above, such as the impact of unrealized foreign exchange gains and losses on U.S. dollar denominated long-term debt, the impairment of assets in Libya, the increase in the U.K. tax rate and gains and losses on the disposal of significant assets.

Operating earnings for 2011 were $5.674 billion compared to $2.634 billion in 2010. The increase in operating earnings was due mainly to higher average upstream price realizations for crude oil production, higher refining margins and an increase in production from Oil Sands, where volumes were impacted in the first half of 2010 by two upgrader fires. These increases were partially offset by lower production volumes for the Exploration and Production segment, due mainly to the divestiture of non-core assets throughout 2010 and 2011, and higher operating expenses, primarily due to incremental costs associated with Firebag Stage 3.

Cash flow from operations was $9.746 billion in 2011, compared to $6.656 billion in 2010, and increased due mainly to the same factors impacting operating earnings.

Net debt decreased by $4.278 billion in 2011, due primarily to strong cash flow from operations that exceeded capital expenditures (including capitalized interest) by $2.890 billion and proceeds of $2.232 billion that were received from the Total E&P Canada Ltd. (Total E&P) transaction and the sale of non-core assets in 2011. These factors enabled Suncor to reduce short-term and long-term debt by $1.721 billion and maintain a larger balance of cash and cash equivalents in 2011.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

Year ended December 31	**2012**	2011	2010
WTI crude oil at Cushing (US$/bbl)	**94.20**	95.10	79.55
Dated Brent crude oil at Sullom Voe (US$/bbl)	**111.70**	111.15	79.50
Dated Brent/Maya FOB price differential (US$/bbl)	**12.15**	12.50	9.30
Canadian 0.3% par crude oil at Edmonton (Cdn$/bbl)	**86.60**	95.75	78.05
WCS at Hardisty (US$/bbl)	**73.15**	77.95	65.35
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**21.05**	17.15	14.20
Condensate at Edmonton (US$/bbl)	**100.75**	105.30	81.90
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**2.40**	3.65	4.15
New York Harbor 3-2-1 crack[(1)] (US$/bbl)	**32.90**	27.00	10.55
Chicago 3-2-1 crack[(1)] (US$/bbl)	**27.40**	24.65	9.00
Portland 3-2-1 crack[(1)] (US$/bbl)	**33.40**	28.40	13.55
Gulf Coast 3-2-1 crack[(1)] (US$/bbl)	**29.00**	24.80	9.00
Exchange rate (US$/Cdn$)	**1.00**	1.01	0.97
Exchange rate (end of period) (US$/Cdn$)	**1.01**	0.98	1.01

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced by changes in the price for WTI at Cushing and by the supply and demand of sweet SCO from Western Canada. The average price for WTI in 2012 was US$94.20/bbl and was comparable to the average in 2011 of US$95.10/bbl. In 2012, the WTI price declined as the year progressed and reached its lowest level over the last two years. In 2012 due to oversupply, the average premium for sweet SCO was significantly lower than 2011.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by changes to various crude benchmarks including, but not limited to, Canadian par crude at Edmonton and WCS at Hardisty, but which can also be affected by prices negotiated for spot sales.

Prices for Canadian par crude at Edmonton decreased significantly in 2012, compared to 2011. The average Edmonton par price was $86.60/bbl in 2012 and $95.75/bbl in 2011. Average prices for WCS also decreased from US$77.95/bbl in 2011 to US$73.15/bbl in 2012. The differential between WTI and WCS reached its highest levels over the last two years, which was reflected in unfavourable sour SCO pricing.

Bitumen production that Suncor does not upgrade is blended with diluent (or SCO) to facilitate delivery on pipeline systems to customers. Net bitumen price realizations are, therefore, influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at

Edmonton). Diluent is sourced primarily from the company's own upgrading and refining facilities; however, purchases of diluent from third parties may be required when the company experiences operational outages. Bitumen price realizations can also be affected by bitumen quality and spot sales to manage inventory levels. Average price realizations for bitumen in 2012 were lower than those realized in 2011, due mainly to wider light/heavy differentials, offset by lower prices for diluent. Suncor's integration with inland refineries in the Refining and Marketing segment is recovering much of the impact from widening crude price differentials through lower feedstock costs.

Suncor's price realizations for production from East Coast Canada and International assets are influenced primarily by the price for Brent crude. Brent crude pricing remained strong throughout 2012 and averaged US$111.70/bbl, consistent with the average of US$111.15/bbl in 2011. After reaching an average of US$118.35/bbl in the first quarter of 2012, the Brent crude price stabilized throughout the remainder of the year despite the decline in WTI, resulting in significantly higher premiums to WTI in late 2012.

Suncor's price realizations for North America Onshore natural gas production are primarily referenced to Alberta spot at AECO. The AECO benchmark declined significantly with an average of $2.40/mcf in 2012 compared to $3.65/mcf in 2011.

Suncor's refining margins are influenced primarily by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates, and by light/heavy and light/sour crude differentials, which influence feedstock costs for more complex refineries that process less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery because these benchmarks are calculated based off of WTI. In 2012, crack spreads increased relative to 2011, in part because refined product prices reflected the higher priced Brent crude feedstock of coastal North American markets. This benefited all of Suncor's refineries for much of 2012. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined product sales markets unique to that refinery's supply orbit.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

Conversely, many of Suncor's assets and liabilities are denominated in U.S. dollars, most notably much of the company's long-term debt, and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. An increase in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date decreases the Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities (1)(2)(3)

The following table illustrates the estimated effects that changes in certain factors would have had on 2012 net earnings and cash flow from operations if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Cash Flow From Operations
Crude oil +US$1.00/bbl	88	115
Natural gas +Cdn$0.10/mcf	(3)	(4)
Light/heavy differential +US$1.00/bbl	30	40
3-2-1 crack spreads +US$1.00/bbl	109	140
Foreign exchange +$0.01 US$/Cdn$	(42)	(145)

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.

(3) Differences between estimates for net earnings and cash flow from operations are due primarily to the impacts of cash taxes in certain jurisdictions.

5. SEGMENT RESULTS AND ANALYSIS

OIL SANDS

Strategy and Operational Update

In 2012, the Oil Sands business achieved a number of milestones that contributed to record production.

Firebag Stage 3 reached full ramp up in 2012, while the successful execution of Firebag Stage 4 resulted in first oil from Stage 4 wells in 2012, as well as the commissioning of the central processing facilities and cogeneration units ahead of schedule. The project is near completion and expected to come in approximately 15% under the announced cost estimate. The company anticipates that bitumen production from the Firebag complex will reach production capacity of 180,000 bbls/d over the next year.

With the commissioning of the MNU in the third quarter of 2012, Suncor's upgrading facilities have the ability to generate a larger proportion of higher value SCO. The development of the North Steepbank mining area has provided access to a significant reserves base, and resulted in efficiencies in the mine through reduced mine congestion and lower average haul distances. The company also completed its tailings management project. Through the TRO_{TM} process, mature fine tailings are converted more rapidly into a solid landscape suitable for reclamation. As a result of this new technology and the company's capital investment to reconfigure its tailing operations, Suncor has cancelled plans for five additional tailings ponds.

While growth in 2012 was achieved through the successful execution of major capital projects, the focus in 2013 will be to optimize our current asset base through the development of new infrastructure that will enhance regional takeaway capacity and marketing flexibility, and debottlenecking projects that are expected to provide low-cost efficiencies and higher outputs in Oil Sands operations. In support of these initiatives, the Wood Buffalo pipeline and two of four storage tanks at Hardisty, Alberta were commissioned in late 2012.

The company will also continue to focus on steady production growth and sustainment through active infill and development drilling programs at both Firebag and MacKay River. In addition, the company has commenced a debottlenecking project at the MacKay River central processing facility and expects to increase production to 38,000 bbls/d by 2015.

With a significant resource base, Suncor continues to assess potential in situ growth prospects at Firebag, MacKay River, Meadow Creek and Lewis. Furthermore, Suncor's portfolio of technology projects will not only drive improvements and efficiencies in current production but facilitate in developing these future opportunities. This portfolio focuses on both subsurface and surface challenges, such as reducing steam-to-oil ratios and improving operational efficiency.

The Oil Sands business continues to focus on safe, reliable operations that achieve steady production growth while effectively controlling operating costs. We expect our operational excellence initiatives will continuously improve our plant utilization and workforce productivity. 2012 was a challenging year in terms of reliability in upgrading facilities; however, Suncor continues to work towards higher reliability.

Suncor's Oil Sands Ventures business, dedicated to ensuring the success of new joint arrangements in Alberta's oil sands, continued to work closely with other owners on evaluating and progressing growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.

The partners in the Fort Hills mining project expect to reach a sanction decision in the second half of 2013. Subject to the owners approving the sanction of the project, post sanction activities are expected to include the commencement of detailed engineering design, bulk equipment and material procurement, and site construction. Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn mining project when available.

Suncor's view is that the economic outlook for the Voyageur upgrader project is challenged. Suncor and its partner continue to work diligently towards determining an outcome for the project. The partners have been considering options for the project, including the implications of cancellation or indefinite deferral. No formal decisions regarding the project have been made and the partners continue to work toward a decision by the end of the first quarter of 2013. The Voyageur upgrader project cannot be sanctioned to proceed without the approval of both partners and, in the case of Suncor, Suncor's Board of Directors. In the interim, Suncor and its partner have agreed to minimize expenditures on the project pending a decision.

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Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Gross revenues (1)	**11 502**	12 003	9 002
Less: Royalties	**(684)**	(799)	(681)
Operating revenues, net of royalties (1)	**10 818**	11 204	8 321
Net earnings	**458**	2 603	1 520
Operating earnings (2)			
Oil Sands	**1 797**	2 425	1 196
Oil Sands Ventures	**218**	312	183
	2 015	2 737	1 379
Cash flow from operations (2)	**4 407**	4 572	2 777

(1) The company has reclassified prior years' gross revenues and operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands segment net earnings for 2012 were $458 million, compared to $2.603 billion in 2011. Given the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in 2012, based on an assessment of expected future net cash flows; the company recorded an after-tax impairment charge of $1.487 billion. Net earnings were further reduced for 2012 due to a deferred tax adjustment of $70 million related to an income tax rate change. Net earnings for 2011 included a loss of $99 million on the sale of partial interests in the Voyageur upgrader project and the Fort Hills mining project and an after-tax write-off of $35 million for third-party pipeline adjustments.

Oil Sands operations contributed $1.797 billion to operating earnings, while Oil Sands Ventures contributed $218 million. The decrease in operating earnings for Oil Sands operations from $2.425 billion in 2011 to $1.797 billion in 2012 was due primarily to lower price realizations and higher DD&A, partially offset by higher bitumen sales volumes. Operating earnings for Oil Sands Ventures decreased from $312 million in 2011 to $218 million in 2012, due primarily to lower price realizations at Syncrude.

Cash flow from operations for the Oil Sands segment was $4.407 billion in 2012, compared to $4.572 billion in 2011. The decrease was due primarily to lower price realizations, partially offset by higher bitumen sales volumes.

Operating Earnings

Operating Earnings Reconciliation

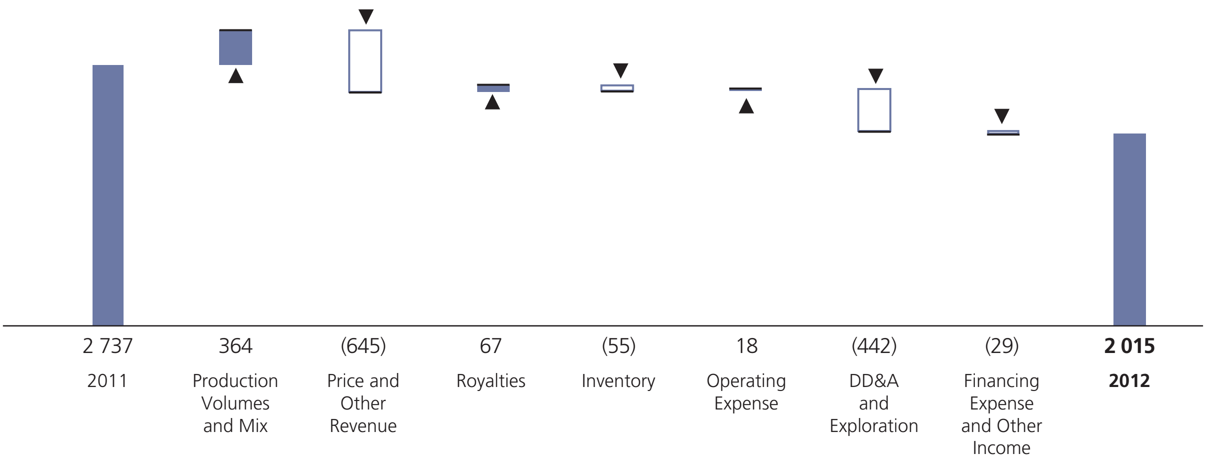
Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**458**	2 603	1 520
Impairments and write-offs	**1 487**	35	143
Impact of income tax rate adjustments on deferred income taxes	**70**	—	—
Loss on significant disposals	**—**	99	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	—	(233)
Modification of the BVM	**—**	—	(51)
Operating earnings (1)	**2 015**	2 737	1 379

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

OIL SANDS

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Production Volumes[1]

Year ended December 31 (mbbls/d)	**2012**	2011	2010
Upgraded product (SCO)	**276.7**	279.7	251.4
Non-upgraded bitumen	**48.1**	25.0	31.6
Oil Sands	**324.8**	304.7	283.0
Oil Sands Ventures – Syncrude	**34.4**	34.6	35.2
Total	**359.2**	339.3	318.2

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen from In Situ operations is upgraded or sold directly to customers. Yields of SCO and diesel from Suncor's upgrading processes are approximately 79% of bitumen feedstock input. See also the Bitumen from Operations table presented below.

The Oil Sands segment achieved record production with an average of 359,200 bbls/d in 2012, increasing from 339,300 bbls/d in 2011. The increase in Oil Sands production was primarily due to the ramp up of production from Firebag.

Production of upgraded product (sweet SCO, sour SCO and diesel) averaged 276,700 bbls/d in 2012, compared to 279,700 bbls/d in 2011. Production in 2012 was impacted by planned maintenance on various coker units and hydrotreating units in Upgrader 1 and 2, as well as unplanned maintenance relating to primary and secondary upgrading at Upgrader 2. Production in 2011 was impacted by the completion of a six-week planned maintenance event at Upgrader 2 facilities and unplanned maintenance at the Upgrader 1 hydrogen plant. Although the scope of planned maintenance completed in 2012 was much smaller, the unplanned maintenance activities constrained production in the year. Non-upgraded bitumen production averaged 48,100 bbls/d in 2012, compared to 25,000 bbls/d in 2011, and increased due primarily to higher production from Firebag.

Suncor's share of Syncrude production and sales averaged 34,400 bbls/d in 2012, compared to 34,600 bbls/d in 2011. Production was impacted by a similar amount in 2012 and 2011 due to unplanned maintenance.

Bitumen from Operations

Year ended December 31	**2012**	2011	2010
Oil Sands Base			
Production (mbbls/d)	**266.2**	287.1	266.2
Ore mined (thousands of tonnes per day)	**412.3**	441.1	391.9
Bitumen ore grade quality (bbls/tonne)	**0.65**	0.65	0.68
In Situ bitumen production (mbbls/d)			
Firebag	**104.0**	59.5	53.6
MacKay River	**27.0**	30.0	31.5
Total In Situ production	**131.0**	89.5	85.1
In Situ steam-to-oil ratio			
Firebag	**3.4**	3.6	3.2
MacKay River	**2.4**	2.2	2.4

Bitumen from Oil Sands Base operations averaged 266,200 bbls/d in 2012, compared to 287,100 bbls/d in 2011. The decline in bitumen production was due primarily to reduced mining activity in 2012 to coincide with lower upgrader availability that was constrained by maintenance activities. For the majority of the year, the company had been mining through a lower ore grade quality of the Millennium mining area; however, by the fourth quarter of 2012, Suncor had worked through the area of lower bitumen ore grade quality, as planned.

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Bitumen from In Situ operations averaged 131,000 bbls/d in 2012, increasing from 89,500 bbls/d in 2011.

- Production from Firebag averaged 104,000 bbls/d in 2012 compared to 59,500 bbls/d in 2011. Stage 3 central processing facilities reached design rates approximately one year after achieving first oil in August 2011, while Stage 4 cogeneration units and central processing facilities were commissioned ahead of schedule, with the central processing facility operating at 10% capacity throughout the fourth quarter of 2012. Production from Firebag is expected to reach production capacity of 180,000 bbls/d over the next year.
- Production from MacKay River averaged 27,000 bbls/d in 2012, compared to 30,000 bbls/d in 2011, and decreased primarily due to increased planned maintenance activities in 2012 and natural declines in older wells. In order to maintain production levels, the company began steaming wells on a new pad in December 2012, with first oil from these wells anticipated in the first quarter of 2013.

Sales Volumes and Mix

Year ended December 31	2012	2011	2010
Oil Sands sales volumes (mbbls/d)			
Sweet SCO	**93.8**	85.5	82.3
Diesel	**24.5**	24.3	20.4
Sour SCO	**161.1**	170.6	145.2
Upgraded Product (SCO)	**279.4**	280.4	247.9
Non-upgraded bitumen	**44.5**	24.0	31.4
	323.9	304.4	279.3

Sales volumes for Oil Sands operations increased to 323,900 bbls/d in 2012, compared to 304,400 bbls/d in 2011.

- Sales volumes of sweet product (sweet SCO and diesel) increased in 2012, compared to 2011. The start-up of operations for the MNU in the third quarter of 2012 enabled Suncor to maintain a more profitable SCO sales mix during maintenance at Upgrader 2 in 2012. In 2011, sales of sweet product were impacted by the planned maintenance event at Upgrader 2 and unplanned maintenance at the Upgrader 1 hydrogen plant.
- Sales volumes of non-upgraded bitumen increased in 2012, compared to 2011, mainly due to the incremental Firebag volumes in 2012 resulting in higher non-upgraded bitumen production from Firebag.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	2012	2011	2010
Oil Sands			
Sweet SCO and diesel	**96.95**	103.95	74.71
Sour SCO and non-upgraded bitumen	**72.93**	80.17	66.60
Crude sales basket (all products)	**81.69**	88.74	69.58
Crude sales basket, relative to WTI	**(12.44)**	(5.35)	(12.33)
Oil Sands Ventures			
Syncrude – Sweet SCO	**92.69**	101.80	80.93
Syncrude, relative to WTI	**(1.50)**	7.71	(0.98)

Average price realizations for Oil Sands operations decreased to $81.69/bbl in 2012 from $88.74/bbl in 2011, due to a higher proportion of non-upgraded bitumen sales in 2012, combined with less favourable price differentials. Although the average price for WTI remained relatively constant from 2011, the average premium for sweet SCO relative to WTI was lower by approximately $6/bbl. Sour SCO and non-upgraded bitumen prices reflected the widening discount for WCS relative to WTI. As a result, the average price realization for Oil Sands operations relative to WTI was WTI less $12.44/bbl in 2012, compared with WTI less $5.35/bbl in 2011.

Suncor's average price realization for Syncrude sales in 2012 was $92.69/bbl, compared to $101.80/bbl in 2011, primarily due to less favourable differentials between sweet SCO and WTI in 2012.

Royalties

Royalties were lower in 2012 relative to 2011 due to lower benchmark prices for WCS that influenced the company's regulated bitumen valuation methodology used to determine royalties for mining properties. Higher eligible capital costs deductions at Syncrude for large sustaining capital expenditures also contributed to lower royalties in 2012.

Inventory

The Inventory variance factor decreased operating earnings due to a large build in inventory at the end of 2012, resulting from increased non-upgraded bitumen production and line fill required for assets that were brought into service in late 2012, including the Wood Buffalo pipeline and two storage tanks in Hardisty, Alberta.

Expenses and Other Factors

Operating expenses for 2012 were slightly higher than 2011. Factors contributing to the change in operating expenses included:

- Cash operating costs for Oil Sands operations increased slightly to $4.395 billion in 2012 from $4.355 billion in 2011 due to the incremental costs required to operate assets brought into service in the current year, including Firebag Stage 4 central processing facilities and the MNU, partially offset by lower natural gas prices, the net benefit provided by higher power sales and operating efficiencies, including the benefits associated with the North Steepbank mining area.
- Other operating expenses were higher in 2012 than 2011 due primarily to higher share-based compensation expense and higher costs related to remobilizing certain growth projects out of "safe mode" after the economic downturn in late 2008 and early 2009, partially offset by lower costs relating to the reduced scope of start-up activity for Firebag Stage 4, and the receipt of pipeline transportation credits.
- Operating expenses at Syncrude were lower for 2012 than 2011, as a result of lower fuel costs and lower planned maintenance expenditures.

DD&A expense for 2012 was higher than 2011, due to the larger asset base that is the result of commissioning additional Firebag assets, the TRO_{TM} project, the MNU, the North Steepbank mining area, and the costs capitalized as part of planned maintenance events.

Cash Operating Costs Reconciliation [1][2]

Year ended December 31	**2012**	2011	2010
Operating, selling and general expense (OS&G)	**5 375**	5 169	4 537
Syncrude OS&G	**(513)**	(529)	(473)
Non-production costs [3]	**(338)**	(275)	(305)
Other [4]	**(129)**	(10)	32
Oil Sands cash operating costs ($ millions)	**4 395**	4 355	3 791
Oil sands cash operating costs ($/bbl)	**37.05**	39.05	36.70

(1) Cash operating costs and cash operating costs per barrel are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this document.

(2) Effective as of the first quarter of 2012, the calculation of cash operating costs has been revised to better reflect the ongoing cash costs of production, and prior period figures have been redetermined. See the Non-GAAP Financial Measures Advisory section of this document.

(3) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes.

(4) Other includes the impacts of changes in inventory valuation and operating revenues associated with excess power from cogeneration units.

Oil Sands cash operating costs per barrel decreased in 2012, averaging $37.05/bbl, compared to $39.05/bbl in 2011 due to higher production volumes while total cash operating costs increased slightly. Total cash operating costs in 2012 were impacted by the incremental costs required to operate assets brought into service in the current year, including Firebag Stage 4 central processing facilities and the MNU, partially offset by lower natural gas prices, the net benefit provided by higher power sales and operating efficiencies, including the benefits associated with the North Steepbank mining area.

Voyageur Upgrader Project Impairment

Given the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in the fourth quarter of 2012. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion, after which the company's carrying value for net assets relating to the Voyageur upgrader project as at December 31, 2012 was approximately $345 million.

Planned Maintenance Events

The company plans to commence refurbishing the Upgrader 1 hydrogen plant late in the first quarter of 2013, which is expected to be offline for approximately 14 weeks. The decrease in sweet SCO production during this outage is expected to be partially offset by the additional hydrotreating capacity from the MNU.

The company has scheduled a planned maintenance event for its Upgrader 1 facility in the second quarter of 2013. The event is scheduled for approximately seven weeks, during which time there will be no production from Upgrader 1. Within this outage, the company anticipates completing planned maintenance at one of the Firebag central processing facilities.

Planned maintenance is also scheduled in the third quarter of 2013 for the company's Upgrader 2 facilities, which is anticipated to have an impact on SCO production.

The production impact of the maintenance discussed above has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Oil Sands net earnings for 2011 were $2.603 billion, compared to $1.520 billion in 2010. Net earnings in 2011

OIL SANDS

included an after-tax loss on the partial disposition of interests in the Voyageur upgrader and Fort Hills mining projects. Net earnings for 2010 included after-tax gains of $233 million for the change in fair value of commodity derivatives used for risk management and $51 million for a recovery of royalties pertaining to a change in Suncor's BVM, partially offset by after-tax write-offs of $143 million primarily associated with equipment for an alternative mining and extraction process that was discontinued.

Operating earnings for 2011 were $2.737 billion, compared to $1.379 billion in 2010, and increased primarily due to higher average price realizations and higher production volumes, offset by higher operating expenses and DD&A. Production volumes were lower during the first half of 2010 due mainly to the impacts of the two upgrader fires. Operating expenses were higher in 2011, due mainly to costs associated with the start of operations for Firebag 3 and with unplanned maintenance on secondary upgrading units at Upgrader 1. DD&A was higher, due mainly to commissioning assets such as Firebag 3 and the 2011 planned maintenance event.

Cash flow from operations for 2011 was $4.572 billion, compared to $2.777 billion in 2010, due primarily to higher margins, which were driven by higher price realizations and higher production volumes.

During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project and increased Total E&P's working interest in the Fort Hills oil sands mining project, and which brought Suncor into the Joslyn oil sands mining project. In consideration for Total E&P acquiring a 49% interest in the Voyageur upgrader project, an additional 19.2% interest in the Fort Hills project, rights to certain knowledge and technology licences, and Total E&P assuming its share of capital expenditures subsequent to the transaction effective date of January 1, 2011, Suncor received $2.662 billion from Total E&P, net of transaction costs. Suncor recorded an after-tax loss of $99 million on the partial disposition of its assets, which included a reduction of $267 million to goodwill that the company allocated to its disposed interests. In consideration for Suncor acquiring a 36.75% interest in Joslyn and assuming its share of capital expenditures subsequent to the effective date, Suncor paid Total E&P $842 million.

EXPLORATION AND PRODUCTION

Strategy and Operational Update

Suncor's Exploration and Production operations are mainly comprised of conventional upstream assets. The Exploration and Production segment continued to generate significant cash flow for Suncor, and remains an important source of funding for future growth. Profitability was also realized through high price realization as over 70% of 2012 production from this segment received prices based on Brent crude, which traded at a significant premium to WTI.

As noted, 2012 results for the Exploration and Production segment were highlighted by planned maintenance activities at all offshore facilities, including the replacement of the floating production, storage and offloading vessels (FPSO) water injection swivel and subsea infrastructure at Terra Nova and the repair of the FPSO propulsion system and other maintenance at White Rose. Production levels in Libya were strong following the restart of production after the regime change in 2011. Suncor is encouraged by this progress and is working to restart exploration activities in 2013.

The year was not without its challenges. Operations in Syria remained suspended throughout 2012 as a result of political unrest and international sanctions against that country. North American natural gas prices were very low throughout the year, resulting in the shut in of production in certain areas in Western Canada.

In support of the company's focus on long term profitable growth through its core assets, combined with a view that market conditions are improving, Suncor continues to explore opportunities to divest non-core properties, and will pursue those opportunities that meets its financial objectives.

Growth from the Exploration and Production segment is an important focus for Suncor, with approximately half of Suncor's 2013 growth capital targeted towards advancing projects within the segment. The company and co-owners announced sanction of the Hebron project offshore Newfoundland and Labrador in the fourth quarter of 2012. The estimated gross oil production capacity for Hebron is 150,000 bbls/d with initial production estimated late in 2017.

The company and co-owners of the Golden Eagle project in the UK sector of the North Sea continued to progress development in 2012, with initial production estimated in late 2014 or early 2015.

The company also plans to leverage and extend the productive life of existing offshore infrastructure, with drilling activities in areas adjacent to producing fields, such as the HSEU, the White Rose Extensions, and the Northern Terrace area for Buzzard.

Longer term, there is potential for new prospects offshore Norway, where the company is increasingly acting as operator for its growing exploration portfolio, and in the mature U.K. North Sea and East Coast Canada basins.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Gross revenues	**6 476**	6 784	7 043
Less: Royalties	**(1 631)**	(1 472)	(1 377)
Operating revenues, net of royalties	**4 845**	5 312	5 666
Net earnings	**138**	306	1 938
Operating earnings (1)			
East Coast Canada	**422**	694	407
International	**538**	708	793
North America Onshore	**(110)**	(44)	(7)
	850	1 358	1 193
Cash flow from operations (1)	**2 227**	2 846	3 325

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Exploration and Production net earnings for 2012 were $138 million, compared to $306 million for 2011. Net earnings for 2012 included total impairments (net of reversals), write-offs and provisions of $689 million. The company recorded after-tax impairment (net of reversals) and write-offs of $517 million for assets in Syria, after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore, and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity. Net earnings also included a deferred income tax charge of $23 million related to an income tax rate change.

Net earnings for 2011 included after-tax impairments (net of reversals) of $571 million comprised of an after-tax impairment (net of reversals) of $503 million for assets in Libya as a result of the shut in of production, and $68 million against certain North America Onshore properties due to decreasing price forecasts. Net earnings in 2011 were also impacted by a deferred income tax charge of $442 million pertaining to an increase in the U.K. statutory income tax rate, an after-tax provision of $31 million pertaining to a royalty dispute covering a period from before the merger, and after-tax losses on the disposal of non-core assets of $8 million.

For 2012, operating earnings for East Coast Canada were $422 million, compared to $694 million for 2011, and were lower due primarily to planned off-station maintenance programs at Terra Nova, White Rose and Hibernia that decreased production. Operating earnings for International were $538 million for 2012, compared to $708 million for 2011, and were lower primarily due to the suspension of operations in Syria, higher income tax expense in the UK due to a statutory income tax rate increase, and higher exploration and well write-offs, partially offset by the resumption of operations in Libya and higher price realizations in 2012. The operating loss for North America Onshore was $110 million for 2012, compared with an operating loss of $44 million for 2011, due to lower natural gas prices and production volumes.

Cash flow from operations was $2.227 billion in 2012, compared to $2.846 billion in 2011, and decreased primarily due to the same factors that affected operating earnings.

EXPLORATION AND PRODUCTION

Operating Earnings

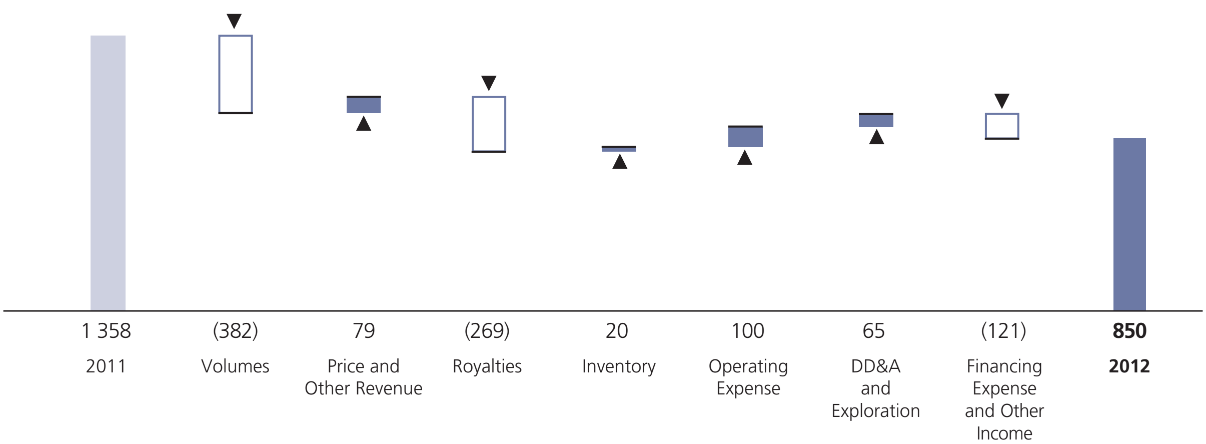
Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**138**	306	1 938
Impairments (net of reversals), write-offs and provisions	**689**	571	163
Impact of income tax rate adjustments on deferred income taxes	**23**	442	—
Adjustments to provisions for assets acquired through the merger	**—**	31	84
Loss (gain) on significant disposals	**—**	8	(826)
Redetermination of working interest in Terra Nova	**—**	—	(166)
Operating earnings (1)	**850**	1 358	1 193

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings(1)

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Production Volumes

Year ended December 31	**2012**	2011	2010
Production volumes (mboe/d)	**189.9**	206.7	296.9
East Coast Canada (mbbls/d)	**46.5**	65.6	68.6
International (mboe/d)	**89.5**	76.4	132.5
North America Onshore (mmcfe/d)	**323**	388	575
Production Mix (liquids/gas) (%)	**74/26**	64/36	63/37
East Coast Canada	**100/0**	100/0	100/0
International	**99/1**	82/18	87/13
North America Onshore	**10/90**	8/92	9/91

East Coast Canada production averaged 46,500 bbls/d in 2012, compared to 65,600 bbls/d in 2011.

- Production from Terra Nova averaged 8,800 bbls/d in 2012, compared to 16,200 bbls/d in 2011. Production was shut in for 27 weeks during 2012 for a dockside maintenance program to replace the FPSO water injection swivel and complete other routine planned maintenance. Suncor also used this outage to perform work on subsea infrastructure to help mitigate hydrogen sulphide (H_2S) issues. Following the dockside maintenance program, production from the largest drill centre resumed in December, while production from a second drill centre was delayed until February 2013. The third drill centre is expected to be commissioned in the third quarter of 2013 when faulty flow lines can be replaced. Despite the impact on production from not commissioning the third drill centre, the company expects to meet 2013 guidance in respect of East Coast Canada production.
- Production from White Rose averaged 11,600 bbls/d in 2012, compared to 18,500 bbls/d in 2011. Production was shut in for 15 weeks during 2012 for an off-station maintenance program to repair the FPSO propulsion system, in addition to other routine planned maintenance activities.

EXPLORATION AND PRODUCTION

- Production from Hibernia averaged 26,100 bbls/d in 2012, compared to 30,900 bbls/d in 2011. Production was shut in for four weeks for planned maintenance. Natural declines from older wells were partially offset by production increases from ongoing development drilling.

International production averaged 89,500 boe/d in 2012, compared to 76,400 boe/d in 2011.

- Production from the North Sea averaged 48,000 boe/d in 2012, compared to 46,700 boe/d in 2011. Higher production from Buzzard reflected improved reliability during 2012. In 2011, production from Buzzard was constrained due to replacement of the gas compression cooling system, downtime and capacity constraints on a third-party export pipeline, and other outages that coincided with the commissioning of the fourth platform. Production in 2011 included 3,800 boe/d from non-core U.K. assets that were divested in the first quarter of 2011.
- Production from Libya averaged 41,500 bbls/d in 2012, compared to 12,100 bbls/d in 2011. Production from Libya was suspended throughout much of 2011 due to the outbreak of political unrest and international sanctions. Subsequent to the government regime change and the lifting of sanctions, production was restarted later in the year and had resumed in all major fields by the first quarter of 2012.
- In December 2011, the company declared force majeure under its contractual obligations in Syria due to political unrest and international sanctions affecting that country. As a result, the company recorded no production from Syria for 2012. Production from Syria averaged 17,600 boe/d in 2011.

North America Onshore production averaged 323 mmcfe/d in 2012, compared to 388 mmcfe/d in 2011.

- During the first half of 2012, the shut in of production from certain fields in southwest Alberta and northeast B.C., in response to low natural gas prices and the closure of a natural gas facility, contributed production of approximately 25 mmcfe/d in 2011.
- Throughout 2011, the company divested non-core assets that contributed production of approximately 14 mmcfe/d in 2011.
- Production from remaining properties decreased in 2012 primarily due to natural declines.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties	**2012**	2011	2010
Exploration and Production ($/boe)	**84.05**	79.95	61.06
East Coast Canada ($/bbl)	**112.15**	108.42	80.20
International ($/boe)	**108.22**	100.89	74.92
North America Onshore ($/mcfe)	**3.28**	4.39	4.70

In 2012, average price realizations for crude oil from East Coast Canada were higher than 2011. Although the price for Brent crude for 2012 was consistent with the prior year, price realizations in East Coast Canada increased to $112.15/bbl in 2012 compared to $108.42/bbl in 2011, primarily due to higher production in the first quarter of 2012 when the price for Brent crude was at its highest for the year.

For International, average price realizations were higher in 2012 due to the mix impact of adding higher priced crude oil production from Libya and removing natural gas production from Syria.

Average price realizations for North America Onshore were lower due primarily to lower benchmark prices for natural gas.

Royalties

Royalties were higher in 2012, compared with 2011, due primarily to higher production from Libya, where effective royalty rates are substantially higher than those for other Exploration and Production assets. This increase was partially offset by lower royalties from less production in East Coast Canada and North America Onshore in comparison to 2011, and the suspension of operations in Syria in 2012.

Expenses and Other Factors

Operating expenses were lower in 2012 than in 2011 due to lower production volumes in East Coast Canada, lower production in North America Onshore and the suspension of operations in Syria, partially offset by higher incremental expenses associated with planned maintenance in 2012 and the resumption of operations in Libya.

In March 2012, while drilling an exploratory natural gas well in B.C., a fire occurred on a drilling rig. The fire was brought under control in early April, and the well was subsequently capped. Operating expenses associated with the containment and monitoring of this well were approximately $43 million before tax, partially offset by $25 million before tax in partial insurance proceeds received in the fourth quarter of 2012.

EXPLORATION AND PRODUCTION

DD&A and exploration expenses were lower in 2012 due primarily to less production, partially offset by higher exploration write-offs. The company wrote off $145 million in exploration expenditures ($42 million after-tax) in 2012, primarily associated with a second appraisal well for the Beta discovery and an exploration well for the Cooper prospect.

Financing expense and other income was impacted by a higher effective tax rate in 2012 due to an increase in the statutory tax rate in the U.K. and the impact of reinvesting proceeds from U.K. asset disposals in 2011.

Impairment and Write-Off of Syrian Assets

As a result of the political unrest that began in Syria in the latter half of 2011 and ensuing international sanctions, Suncor declared force majeure under its contractual obligations and suspended operations in the country in December 2011. In the second quarter of 2012, Suncor estimated the net recoverable value of its assets in Syria based on an assessment of expected future net cash flows over a range of possible outcomes. Based on this assessment, the company recorded impairment charges of $604 million against property, plant and equipment. In the same quarter, the company recorded a further write-down of $67 million against remaining accounts receivable and a write-off of $23 million for other current assets.

In the fourth quarter of 2012, the company received risk mitigation proceeds of $300 million pertaining to the suspension of the company's operations in Syria. A portion, or all, of these proceeds may be repayable if operations in Syria resume. As a result, the proceeds were not recorded in earnings but rather as a provision. Suncor re-estimated the net recoverable value of its assets in Syria at the end of 2012, extending the future potential dates for the resumption of operations further into the future and including repayment of risk mitigation proceeds in scenarios where operations resumed. As a result of the changes, the company reversed $177 million of the impairment charges recorded earlier in the year.

Impairments (net of reversals) and write-offs in 2012 were $517 million, net of income taxes of $nil. After impairments (net of reversals) and write-offs, the carrying value of Suncor's property, plant and equipment in Syria net of the risk mitigation provision as at December 31, 2012 was approximately $130 million.

Planned Maintenance Events

Routine annual planned maintenance has been scheduled for Terra Nova, White Rose and Buzzard in the second and third quarters of 2013.

The production impact of this maintenance has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Exploration and Production net earnings for 2011 were $306 billion, compared to $1.938 million in 2010. Net earnings in 2010 included after-tax gains of $826 million on the disposal of non-core assets, an after-tax gain of $166 million for the redetermination of Suncor's working interest in Terra Nova, after-tax impairment charges of $111 million on certain North America Onshore assets mainly due to lower natural gas prices, an after-tax provision of $84 million related to losses on unfavourable natural gas pipeline commitments, and after-tax impairment charges of $52 million on non-core U.K. assets that were divested.

Operating earnings for 2011 were $1.358 billion, compared to $1.193 billion for 2010, and increased primarily due to higher price realizations and lower operating expenses and DD&A, partially offset by lower production volumes, higher royalties and a higher effective tax rate on U.K. earnings.

Cash flow from operations was $2.846 billion for 2011, compared to $3.325 billion for 2010. The decrease in cash flow from operations relative to the increase in operating earnings was due primarily to lower production from assets in 2011 that contributed relatively more to cash flow from operations than operating earnings for 2010. In addition, cash flow from operations in 2010 included the gain from the settlement pertaining to the redetermination of working interests in Terra Nova.

REFINING AND MARKETING

Strategy and Operational Update

Results from 2012 for the Refining and Marketing segment were strong, reinforcing the value of an integrated business model to Suncor's overall strategy. The Refining and Marketing segment translated lower price realizations impacting the Oil Sands to strong refining margins. The segments financial performance was supported by 100% utilization rates at the company's Western North America refineries.

In 2012, the company's inland refinery network (Edmonton, Sarnia and Commerce City) was again able to capture the favourable WTI to Brent and Canadian crude differentials through strong refining margins. The integration of these refineries with crude output from Suncor's Oil Sands segment also resulted in lower feedstock costs. Suncor's focus on reliability and continuous improvements enabled the company to sustain high throughput levels, which resulted in nameplate capacity increases for the Sarnia and Commerce City refineries, effective January 1, 2012, and the Edmonton refinery, effective January 1, 2013.

In 2013, Suncor will continue to focus on optimizing overall integration. As bitumen production exceeds upgrading capacity in the Oil Sands, the company continues to explore opportunities to capture the potential value in the refining operations. In 2013, the company will focus on bringing the Montreal refinery into the inland refining network, and plans to transport western Canadian crudes via rail to the refinery.

Suncor's Petro-Canada branded outlets continue to be a leading retailer by market share in major urban areas of Canada. Increased competition and fluctuating demand in key retail markets are expected to be offset by growth in wholesale channels. Refining and Marketing will continue to leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes, and expand the lubricants product offering.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Operating revenues	**26 321**	25 713	20 860
Net earnings	**2 129**	1 726	819
Operating earnings (1)			
Refining and Product Supply	**1 869**	1 413	532
Marketing	**275**	313	264
	2 144	1 726	796
Cash flow from operations (1)	**3 150**	2 574	1 538

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Refining and Marketing recorded net earnings of $2.129 billion and operating earnings of $2.144 billion in 2012, compared with net and operating earnings of $1.726 billion in 2011.

Refining and Product Supply operations contributed $1.869 billion to operating earnings in 2012, a significant increase compared with 2011, primarily due to higher refining margins from lower costs for inland heavy, synthetic, and conventional crude feedstock, higher benchmark refining margins, and higher refinery utilization, slightly offset by the negative impacts of a decreasing crude price environment, whereby inventories produced during periods of higher feedstock costs were sold and replaced with inventories purchased at relatively lower feedstock costs. Marketing operations contributed $275 million to operating earnings in 2012, which was lower than in 2011, due mainly to lower sales volumes and margins in the retail channel.

Cash flow from operations was $3.150 billion in 2012, compared to $2.574 billion in 2011, and increased primarily due to the same factors that affected operating earnings.

Operating Earnings

Operating Earnings Reconciliation

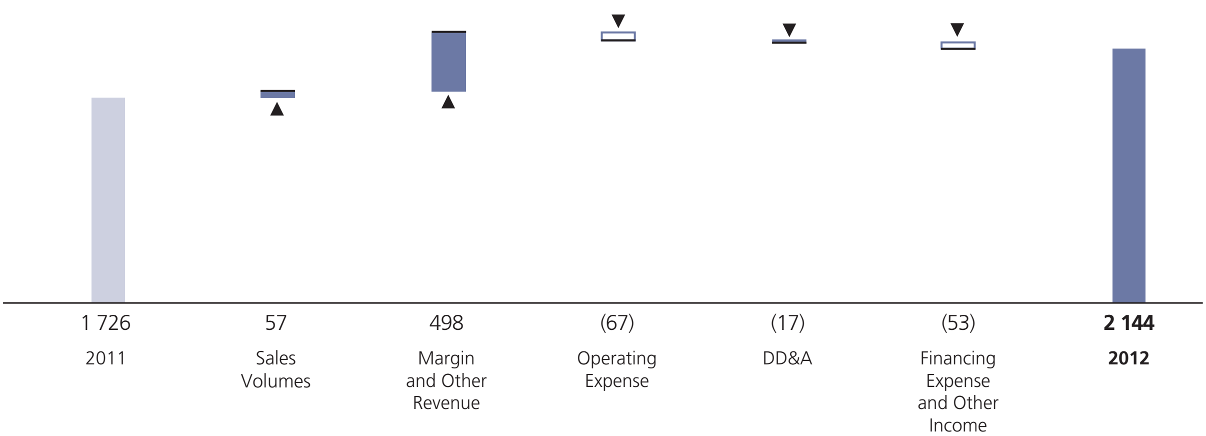
Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**2 129**	1 726	819
Impact of income tax rate adjustments on deferred income taxes	**15**	—	—
Adjustments to provisions for assets acquired through the merger	**—**	—	(23)
Operating earnings (1)	**2 144**	1 726	796

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

REFINING AND MARKETING

Bridge Analysis of Operating Earnings(1)

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Volumes

Year ended December 31	2012	2011	2010
Crude oil processed (thousands of m^3/d)			
Eastern North America	**31.4**	32.0	30.5
Western North America	**37.2**	32.8	34.6
Refinery utilization (1)(2) (%)			
Eastern North America	**89**	94	89
Western North America	**100**	91	95
Refined Product Sales (thousands of m^3/d)			
Gasoline	**40.2**	39.7	41.1
Distillate	**31.0**	30.4	30.4
Other	**14.4**	13.0	15.8
	85.6	83.1	87.3

(1) Effective January 1, 2012, the company increased the nameplate capacity of the Montreal refinery from 130,000 bbls/d (20.7 m^3/d) to 137,000 bbls/d (21.8 m^3/d) and the nameplate capacity of the Commerce City refinery from 93,000 bbls/d (14.8 m^3/d) to 98,000 bbls/d (15.6 m^3/d). Prior years' utilization rates have not been recalculated and reflect the lower nameplate capacities. Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d (21.5 m^3/d) to 140,000 bbls/d (22.3 m^3/d). Figures above have not been recalculated to reflect the revised nameplate capacity.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Total sales of refined petroleum products increased to an average of 85,600 m^3/d in 2012, compared to 83,100 m^3/d in 2011. Suncor was able to meet the higher demands for gasoline and distillate in Western North America through reliability and continuous improvements in the Edmonton refinery. Suncor increased the nameplate capacity of the Edmonton refinery to 140,000 bbls/d from 135,000 bbls/d, effective January 1, 2013. Gasoline and distillate sales in Eastern North America were impacted by weaker demand and increased competition.

Refinery utilization in Eastern North America averaged 89% in 2012, compared to 94% in 2011. Refinery utilization in 2012 was impacted by an unplanned outage of a crude unit at the Sarnia refinery in the first quarter of 2012, a reduction in feedstock availability in the second quarter due to an unplanned Oil Sands upgrader outage, and a scheduled maintenance event at the Sarnia refinery in the fourth quarter of 2012.

Refineries in Western North America ran at full capacity for the majority of 2012, with an average utilization of 100% in 2012, compared to 91% in 2011. The increase over the prior year was the result of a month-long disruption to third-party hydrogen supply and a six-week planned maintenance event in the Edmonton refinery in 2011, while refinery utilization at the Commerce City refinery was also impacted by a five-week planned maintenance event during the second quarter of 2011.

Prices and Margins

For Refining and Product Supply, prices and margins for refined products were higher in 2012 compared to 2011, reflecting lower crude feedstock costs and higher crack spreads, partially offset by the inventory valuation impact of a declining crude price environment.

- Prices for Canadian-based crude feedstock for the company's inland refineries were lower in 2012 due mainly to larger discounts reflecting increased industry supply. Sweet SCO sold at a lower premium relative to WTI compared with 2011 and in some months at discounts relative to WTI, in addition to lower prices for bitumen due to wider light/heavy crude oil differentials.
- The impact on earnings pertaining to the declining crude price environment over 2012 decreased after-tax earnings by approximately $153 million, whereas the impact on earnings pertaining to the rising crude price

environment in 2011 increased after-tax earnings by approximately $230 million.

For Marketing, lower margins in retail were partially offset by higher margins in the wholesale channel.

Expenses and Other Factors

Operating expenses were higher in 2012 than in 2011, due to higher share-based compensation expense, partially offset by lower energy prices for natural gas.

The Financing Expense and Other Income factor was negatively impacted by lower gains on risk management activities in the current year and a gain pertaining to the company's investments in marketing entities.

Planned Maintenance Events

The company has scheduled planned maintenance events at the Edmonton refinery on its heavy sour crude train in the second quarter of 2013, with an expected duration of five weeks, and on its sweet synthetic crude unit in the third quarter of 2013, with an expected duration of two weeks. A six-week planned maintenance event is scheduled at the Sarnia refinery for one of its crude units, beginning the third quarter of 2013.

The impact of this maintenance has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Refining and Marketing net and operating earnings for 2011 were $1.726 billion, compared to net earnings of $819 million and operating earnings of $796 million for 2010. Earnings increased primarily due to higher refining margin and the positive impacts of an increasing crude price environment.

Cash flow from operations for 2011 were $2.574 billion, compared to $1.538 billion for 2010, and increased mainly due to the same factors that affected operating earnings.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Strategy and Operational Update

The Energy Trading business continued to add value in 2012 by accessing key logistical transportation and storage assets across North America to support planned increases in production capacity. The Energy Trading business supports the company's production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers, while generating trading earnings through established strategies. The Energy Trading business continues to evaluate additional pipeline agreements to support planned increases in production capacity.

For Renewable Energy, in 2013, the company will continue to progress the Adelaide and Cedar Point wind projects through the regulatory process. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%. The focus for the ethanol operations will be to maintain safe and reliable operations and improve plant profitability through technology improvements.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss)	**58**	(331)	(448)
Operating earnings (loss) (1)			
Renewable Energy	**57**	72	33
Energy Trading	**147**	149	64
Corporate	**(407)**	(346)	(842)
Group Eliminations	**84**	(22)	11
	(119)	(147)	(734)
Cash flow used in operations (1)	**(39)**	(246)	(984)

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Net earnings for Corporate, Energy Trading and Eliminations for 2012 were $58 million, compared to a net loss of $331 million for 2011. In 2012, the Canadian dollar strengthened in relation to the U.S. dollar, with the exchange rate increasing from 0.98 to 1.01, resulting in an after-tax unrealized foreign exchange gain on

U.S. dollar denominated long-term debt of $157 million. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate decreasing from 1.01 to 0.98 and resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $161 million. Net earnings for 2012 also included a deferred tax reduction of $20 million related to an income tax rate change.

The operating loss for Corporate, Energy Trading and Eliminations in 2012 was $119 million, compared with an operating loss of $147 million in 2011. Operating earnings are discussed below.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss) as reported	**58**	(331)	(448)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)
Impairments and write-offs	**—**	23	—
Impact of income tax rate adjustments on deferred income taxes	**(20)**	—	—
Merger and integration costs	**—**	—	79
Adjustments to provisions for assets acquired through the merger	**—**	—	7
Operating loss (1)	**(119)**	(147)	(734)

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

Year ended December 31	**2012**	2011	2010
Power generation marketed (gigawatt hours)	**429**	245	174
Ethanol production (thousands of m^3)	**412.5**	381.5	206.0

Suncor's renewable energy assets contributed operating earnings of $57 million in 2012, compared to $72 million in 2011, and decreased primarily due to lower margins on ethanol sales that reflected higher prices for feedstock, partially offset by an increase in total power generation marketed from 245 gigawatt hours in 2011 compared to 429 gigawatt hours in 2012. In 2011, Suncor commissioned two new wind power projects – the 88-MW, 55-turbine Wintering Hills project in southern Alberta and the 20-MW, eight-turbine Kent Breeze project in southwest Ontario.

Energy Trading

Energy Trading activities contributed operating earnings of $147 million in 2012, compared to $149 million in 2011. Energy trading continued to contribute to operating earnings, primarily through its heavy crude trading strategies that purchase heavy crude oil in Alberta and transport it to markets with more favourable prices.

Corporate

Corporate had an operating loss of $407 million in 2012, compared with an operating loss of $346 million in 2011. The increase in operating loss was due to higher share-based compensation expense and higher DD&A due to the start of depreciation on Suncor's system integration initiative over the second half of 2011.

In 2012, the company capitalized 91% of its borrowing costs as part of the cost of major development assets and construction projects, compared to 85% in 2011.

Group Eliminations

Group Eliminations reflect the elimination of profit on crude oil sales from Oil Sands and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company determines that the refined products produced from intersegment purchases of crude feedstock have been sold to third parties. In 2012, $84 million of after-tax intersegment profit that was previously eliminated was recognized, compared to an elimination of profit of $22 million in 2011.

Results for 2011 compared with 2010

The net loss for Corporate, Energy Trading and Eliminations for 2011 was $331 million, compared to $448 million in 2010. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, resulting in an after-tax unrealized foreign exchange loss of $161 million.

The operating loss for Corporate, Energy Trading and Eliminations for 2011 was $147 million, compared with an operating loss of $734 million in 2010. The lower operating loss in 2011 primarily related to after-tax claims of $243 million for the two Oil Sands Base upgrader fires paid by the company's captive insurance program in 2010 and an after-tax increase of $255 million in capitalized interest in 2011.

6. FOURTH QUARTER 2012 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	**2012**	2011
Net earnings		
Oil Sands	**(1 040)**	790
Exploration and Production	**148**	284
Refining and Marketing	**448**	307
Corporate, Energy Trading and Eliminations	**(118)**	46
Total	**(562)**	1 427
Operating earnings (loss) (1)		
Oil Sands	**447**	835
Exploration and Production	**143**	372
Refining and Marketing	**448**	307
Corporate, Energy Trading and Eliminations	**(38)**	(87)
Total	**1 000**	1 427
Cash flow from (used in) operations (1)		
Oil Sands	**1 090**	1 417
Exploration and Production	**529**	780
Refining and Marketing	**641**	534
Corporate, Energy Trading and Eliminations	**(25)**	(81)
Total	**2 235**	2 650
Production volumes (mboe/d)		
Oil Sands	**378.7**	356.8
Exploration and Production	**177.8**	219.7
Total	**556.5**	576.5

(1) Non-GAAP financial measures. Operating earnings and cash flow from operations are reconciled below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Segment Analysis

Oil Sands

The net loss for the Oil Sands segment was $1.040 billion for the fourth quarter of 2012, compared with net earnings of $790 million for the fourth quarter of 2011. The net loss in the fourth quarter of 2012 included an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project. Oil Sands operating earnings for the fourth quarter of 2012 were $447 million, compared to $835 million for the fourth quarter of 2011. The decrease in operating earnings for Oil Sands operations, compared with the fourth quarter of 2011, was due primarily to lower average price realizations, lower overall margins due to product mix, and higher DD&A, partially offset by lower royalties. Cash flow from operations for the Oil Sands segment for the fourth quarter of 2012 was $1.090 billion, compared to $1.417 billion for the fourth quarter of 2011, and decreased mainly due to lower average price realizations and lower overall margins due to product mix.

Production volumes for Oil Sands operations averaged 342,800 bbls/d for the fourth quarter of 2012, compared to 326,500 bbls/d for the fourth quarter of 2011, and increased primarily due to the ongoing ramp up of production from Firebag. Production of upgraded product decreased to 281,100 bbls/d in the fourth quarter of 2012 from 310,100 bbls/d in the fourth quarter of 2011, primarily due to maintenance at upgrading facilities. Suncor's share of Syncrude production and sales increased to 35,900 bbls/d in the fourth quarter of 2012 from 30,300 bbls/d in the fourth quarter of 2011, due primarily to unplanned maintenance associated with a coker and hydrogen plant in the fourth quarter of 2011.

Exploration and Production

Exploration and Production net earnings were $148 million for the fourth quarter of 2012, compared to $284 million for the fourth quarter of 2011. The company reversed after-tax impairment charges of $177 million against assets in Syria. This reversal was partially offset by after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity.

Exploration and Production operating earnings were $143 million for the fourth quarter of 2012, compared to $372 million for the fourth quarter of 2011. The decrease was due primarily to planned maintenance at Buzzard and Terra Nova, production declines in North America Onshore, the suspension of operations in Syria, partially offset by the receipt of insurance proceeds for the March 2012 drilling rig fire.

Cash flow from operations for Exploration and Production was $529 million for the fourth quarter of 2012, compared to $780 million for the fourth quarter of 2011. Cash flow from operations decreased due primarily to the same factors that decreased operating earnings.

Production volumes were 177.8 mboe/d in the fourth quarter of 2012, compared to 219.7 mboe/d in the fourth quarter of 2011. The decrease in production volumes was due mainly to planned maintenance programs at Terra Nova and Buzzard, and the suspension of operations in Syria, partially offset by higher production in Libya.

Refining and Marketing

Refining and Marketing net and operating earnings were $448 million for the fourth quarter of 2012, compared with net and operating earnings of $307 million for the fourth quarter of 2011. The increase was due to high refining margins resulting from lower costs for feedstock, higher refined products sales and higher refinery utilization.

Refining and Marketing cash flow from operations was $641 million for the fourth quarter of 2012, compared to $534 million for the fourth quarter of 2011, and increased primarily due to the same factors affecting operating earnings.

Refined product sales averaged 87,000 m^3/d in the fourth quarter of 2012, increasing from 81,600 m^3/d in the fourth quarter of 2011, due primarily to a disruption of third-party hydrogen supply to the Edmonton refinery in the fourth quarter of 2011, and strong demand for distillate in the fourth quarter of 2012.

Corporate, Energy Trading and Eliminations

The net loss for Corporate, Energy Trading and Eliminations for the fourth quarter of 2012 was $118 million, compared to net earnings of $46 million for the fourth quarter of 2011. In the fourth quarter of 2012, the Canadian dollar weakened in relation to the U.S. dollar, resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $80 million. In the fourth quarter of 2011, the Canadian dollar strengthened in relation to the U.S. dollar.

The operating loss for Corporate, Energy Trading and Eliminations for the fourth quarter of 2012 was $38 million, compared to an operating loss of $87 million for the fourth quarter of 2011. The decrease in operating loss was due to the net recognition of $43 million of after-tax intersegment profit that was recognized as the related product had been sold to third parties. In the fourth quarter of 2011, the company eliminated $4 million after-tax of intersegment profit.

Operating Earnings[1]

Three months ended December 31 ($ millions)	Oil Sands 2012	Oil Sands 2011	Exploration and Production 2012	Exploration and Production 2011	Refining and Marketing 2012	Refining and Marketing 2011	Corporate, Energy Trading and Eliminations 2012	Corporate, Energy Trading and Eliminations 2011	Total 2012	Total 2011
Net (loss) earnings as reported	**(1 040)**	790	**148**	284	**448**	307	**(118)**	46	**(562)**	1 427
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**80**	(156)	**80**	(156)
Impairments (net of reversals), and write-offs	**1 487**	35	**(5)**	57	**—**	—	**—**	23	**1 482**	115
Loss on significant disposals	**—**	10	**—**	—	**—**	—	**—**	—	**—**	10
Adjustments to provisions for assets acquired through the merger	**—**	—	**—**	31	**—**	—	**—**	—	**—**	31
Operating earnings (loss)	**447**	835	**143**	372	**448**	307	**(38)**	(87)	**1 000**	1 427

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Cash flow from Operations[1]

Three months ended December 31 ($ millions)	Oil Sands 2012	Oil Sands 2011	Exploration and Production 2012	Exploration and Production 2011	Refining and Marketing 2012	Refining and Marketing 2011	Corporate, Energy Trading and Eliminations 2012	Corporate, Energy Trading and Eliminations 2011	Total 2012	Total 2011
Net (loss) earnings	**(1 040)**	790	**148**	284	**448**	307	**(118)**	46	**(562)**	1 427
Adjustments for:										
Depreciation, depletion, amortization and impairment	**2 552**	392	**300**	474	**128**	118	**35**	39	**3 015**	1 023
Deferred income taxes	**(357)**	270	**2**	(30)	**68**	92	**(35)**	(10)	**(322)**	322
Accretion of liabilities	**26**	18	**15**	16	**1**	1	**3**	—	**45**	35
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**91**	(179)	**91**	(179)
Change in fair value of derivative contracts	**—**	—	**1**	—	**(1)**	17	**(20)**	34	**(20)**	51
Loss (gain) on disposal of assets	**—**	16	**—**	(9)	**(5)**	(5)	**—**	—	**(5)**	2
Share-based compensation	**17**	31	**3**	8	**10**	19	**13**	21	**43**	79
Exploration expenses	**—**	—	**21**	—	**—**	—	**—**	—	**21**	—
Settlement of decommissioning and restoration liabilities	**(70)**	(113)	**(10)**	(6)	**(8)**	(11)	**—**	—	**(88)**	(130)
Other	**(38)**	13	**49**	43	**—**	(4)	**6**	(32)	**17**	20
Cash flow from (used in) operations	**1 090**	1 417	**529**	780	**641**	534	**(25)**	(81)	**2 235**	2 650
Decrease (increase) in non-cash working capital	**35**	(47)	**(117)**	9	**(497)**	587	**(481)**	(396)	**(1 060)**	153
Cash flow provided by (used in) operating activities	**1 125**	1 370	**412**	789	**144**	1 121	**(506)**	(477)	**1 175**	2 803

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

7. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2012**	Sept 30 2012	June 30 2012	Mar 31 2012	Dec 31 2011	Sept 30 2011	June 30 2011	Mar 31 2011
Total production (mboe/d)	**556.5**	535.3	542.4	562.3	576.5	546.0	460.0	601.3
Oil Sands	**378.7**	378.9	337.8	341.1	356.8	362.5	277.2	360.6
Exploration and Production	**177.8**	156.4	204.6	221.2	219.7	183.5	182.8	240.7
Revenues and other income								
Operating revenues, net of royalties [1]	**9 444**	9 512	9 599	9 653	9 906	10 235	9 255	8 943
Other income	**91**	89	123	105	60	184	77	132
	9 535	9 601	9 722	9 758	9 966	10 419	9 332	9 075
Net (loss) earnings	**(562)**	1 555	333	1 457	1 427	1 287	562	1 028
per common share – basic (dollars)	**(0.37)**	1.01	0.21	0.93	0.91	0.82	0.36	0.65
per common share – diluted (dollars)	**(0.37)**	1.01	0.20	0.93	0.91	0.76	0.31	0.65
Operating earnings [2]	**1 000**	1 303	1 258	1 329	1 427	1 789	980	1 478
per common share – basic (dollars)	**0.65**	0.85	0.81	0.85	0.91	1.14	0.62	0.94
Cash flow from operations [2]	**2 235**	2 740	2 344	2 426	2 650	2 721	1 982	2 393
per common share – basic (dollars)	**1.46**	1.78	1.51	1.55	1.69	1.73	1.26	1.52
Capital expenditures, including capitalized interest	**2 205**	1 670	1 606	1 478	1 814	1 519	1 941	1 576
ROCE [2] (%) for the twelve months ended	**7.3**	12.5	14.3	14.8	13.8	13.4	11.1	12.5
Common share information (dollars)								
Dividend per common share	**0.13**	0.13	0.13	0.11	0.11	0.11	0.11	0.10
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**32.71**	32.34	29.44	32.59	29.38	26.76	37.80	43.48
New York Stock Exchange (US$)	**32.98**	32.85	28.95	32.70	28.83	25.44	39.10	44.84

(1) The company has reclassified 2011 operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(2) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this document. ROCE excludes capitalized costs related to major projects in progress.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2012**	Sept 30 2012	June 30 2012	Mar 31 2012	Dec 31 2011	Sept 30 2011	June 30 2011	Mar 31 2011
WTI crude oil at Cushing	US$/bbl	**88.20**	92.20	93.50	102.95	94.05	89.75	102.55	94.10
Dated Brent crude oil at Sullom Voe	US$/bbl	**110.10**	109.50	108.90	118.35	109.00	113.40	117.30	104.95
Dated Brent/Maya FOB price differential	US$/bbl	**17.30**	11.90	9.85	9.45	5.55	14.80	14.05	15.65
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**84.35**	84.70	84.45	92.80	98.20	92.50	103.85	88.40
WCS at Hardisty	US$/bbl	**70.05**	70.45	70.60	81.50	83.60	72.10	84.90	71.25
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**18.15**	21.75	22.90	21.45	10.45	17.65	17.65	22.85
Condensate at Edmonton	US$/bbl	**98.10**	96.00	99.40	110.00	108.70	101.65	112.40	98.35
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.05**	2.20	1.85	2.50	3.40	3.70	3.75	3.80
New York Harbor 3-2-1 crack (1)	US$/bbl	**35.95**	37.80	31.95	25.80	22.80	36.45	29.25	19.40
Chicago 3-2-1 crack (1)	US$/bbl	**27.85**	35.15	27.85	18.80	19.20	33.30	29.70	16.45
Portland 3-2-1 crack (1)	US$/bbl	**29.85**	38.15	37.90	27.70	26.45	36.50	29.35	21.40
Gulf Coast 3-2-1 crack (1)	US$/bbl	**27.35**	33.95	29.30	25.45	20.40	33.10	27.30	18.50
Exchange rate	US$/Cdn$	**1.00**	1.00	0.99	1.00	0.98	1.02	1.03	1.01
Exchange rate (end of period)	US$/Cdn$	**1.01**	1.02	0.98	1.00	0.98	0.95	1.04	1.03

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings

Trends in Suncor's quarterly earnings results and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major planned maintenance events – such as the maintenance that occurred at many Exploration and Production assets in the third and fourth quarters of 2012 and the maintenance that occurred at Upgrader 2 in Oil Sands in the second quarter of 2011 – and unplanned maintenance outages, such as the one that occurred at Upgrader 2 in the first half of 2012.

Trends in Suncor's quarterly earnings results and cash flow from operations are also affected by changes in commodity prices, refining crack spreads and foreign exchange rates.

In addition to the impacts of changes in production volumes and business environment, net earnings over the last eight quarters were affected by the following events or significant one-time adjustments:

- Given Suncor's view of the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in the fourth quarter of 2012. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion.
- The fourth quarter of 2012 included an after-tax impairment reversal of $177 million of the impairment charges recorded against its assets in Syria in the second quarter of 2012, due to a revised assessment of the net recoverable value of the underlying assets following the receipt of risk mitigation proceeds.
- The fourth quarter of 2012 included total after-tax impairment charges of $128 million for certain exploration, development and production assets in the Exploration and Production segment.
- The second quarter of 2012 included after-tax impairment charges and write-offs of $694 million against assets in Syria, which reflected the shut in of production due to political unrest and international sanctions. The company ceased recording all production and revenue from its Syrian assets in the fourth quarter of 2011.
- The second quarter of 2011 included after-tax impairment charges of $514 million against assets in Libya, which reflected the shut in of production due to political unrest and international sanctions. Production from all major fields in Libya was successfully restarted by the first quarter of 2012.
- The first quarter of 2011 included a $442 million adjustment to deferred income tax expense related to an increase in U.K. tax rates on oil and gas profits in the North Sea.
- As part of its strategic business alignment subsequent to the merger with Petro-Canada, Suncor divested a number of non-core assets in its Exploration and Production segment throughout 2010 and 2011. Decreases in production volumes in 2011 and the second half of 2010 were due in part to the disposition of these assets. The resulting gains and losses on the disposition of these assets had one-time impacts on net earnings in the quarters in which they occurred.

8. CAPITAL INVESTMENT UPDATE

The Capital Investment Update section contains forward-looking information. See the Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	**2012**	2011	2010
Oil Sands	**4 957**	5 100	3 709
Exploration and Production	**1 261**	874	1 274
Refining and Marketing	**646**	633	667
Corporate, Energy Trading and Eliminations	**95**	243	360
Total	**6 959**	6 850	6 010
Less: capitalized interest on debt	**(587)**	(559)	(301)
	6 372	6 291	5 709

Capital and Exploration Expenditures by Type(1)(2)(3)

Year ended December 31 ($ millions)	Sustaining	Growth	**Total**
Oil Sands	2 293	2 114	**4 407**
Oil Sands Base	*1 342*	*604*	***1 946***
In Situ	*625*	*810*	***1 435***
Oil Sands Ventures	*326*	*700*	***1 026***
Exploration and Production	233	994	**1 227**
Refining and Marketing	637	6	**643**
Corporate, Energy Trading and Eliminations	91	4	**95**
	3 254	3 118	**6 372**

(1) Capital expenditures in this table exclude capitalized interest on debt.

(2) Growth capital expenditures include capital investments that result in i) an increase in production levels at existing Oil Sands operations and Refining and Marketing operations; ii) new facilities or operations that increase overall production; iii) new infrastructure that is required to support higher production levels; iv) new reserves or a positive change in the company's reserves profile in Exploration and Production operations; or v) margin improvement, by increasing revenues or reducing costs.

(3) Sustaining capital expenditures include capital investments that i) ensure compliance or maintain relations with regulators and other stakeholders; ii) improve efficiency and reliability of operations or maintain productive capacity by replacing component assets at the end of their useful lives; iii) deliver existing proved developed reserves for Exploration and Production operations; or iv) maintain current production capacities at existing Oil Sands operations and Refining and Marketing operations.

In 2012, Suncor spent $6.372 billion on capital for property, plant and equipment and exploration activities, and capitalized $587 million of interest on debt towards major development assets and construction projects. Activity in 2012 included the following.

Oil Sands Base

Oil Sands Base capital expenditures were $1.946 billion, of which $1.342 billion was directed towards sustaining activities. Sustaining capital expenditures related primarily to planned maintenance events and the company's TRO_{TM} initiative, and included $496 million towards the construction of infrastructure and mature fine tailings drying facilities that will facilitate the company's TRO_{TM} process going forward. The company commissioned the TRO_{TM} project in the second quarter of 2012.

Oil Sands Base growth capital focused on infrastructure required to support growth in production from Oil Sands operations, including the Wood Buffalo pipeline, which connects the company's Athabasca terminal at the base plant in Fort McMurray to other third-party pipeline infrastructure in Cheecham, Alberta, and the first two of four new storage tanks in Hardisty, Alberta, which will be connected to the Enbridge Mainline system in 2013. Both assets are operated by third parties and subject to long-term arrangements.

In Situ

In Situ capital and exploration expenditures were $1.435 billion, of which $810 million was directed towards growth projects. As a result of the successful execution of Firebag Stage 4, the company commissioned the cogeneration units in the fourth quarter ahead of schedule, while the central processing facilities operated at 10% capacity throughout the fourth quarter of 2012. Steam injection was in progress for both Stage 4 well pads and first oil was achieved by the end of 2012. Capital expenditures for Firebag Stage 4 were $445 million in 2012, bringing total project expenditures to $1.634 billion.

In addition, Suncor continues to construct an insulated pipeline, which will transport bitumen without the requirement for additional diluent between Firebag and Suncor's Athabasca terminal starting in the second quarter of 2013.

In Situ sustaining capital expenditures of $625 million were directed primarily to the design and construction of well pads that are expected to maintain existing production levels from MacKay River and Firebag in future years. In December 2012, the company began steaming wells on a new pad at MacKay River. The company anticipates first oil from these wells in the first quarter of 2013.

Oil Sands Ventures

Suncor's share of capital expenditures for the Syncrude joint operation was $326 million, which included $150 million for mine train replacement at the Mildred Lake mining area and equipment relocation at the Aurora mining area, and $63 million for a composite tailings plant and a centrifuge plant as part of its tailings management plans.

Oil Sands Ventures growth capital expenditures were $700 million in 2012. The Voyageur upgrader project expenditures were focused on validating project scope, developing the project execution plan, engineering and progressing site preparation. The Fort Hills mining project expenditures were directed towards engineering, progressing with site preparation and the procurement of long-lead items. The Joslyn North mining project, which is in the earliest stage of development of the three projects, was focused on design engineering and site preparation.

Exploration and Production

Exploration and Production capital and exploration expenditures were $1.227 billion in 2012, of which $994 million was directed towards growth and exploration.

Growth spending included $217 million for Golden Eagle, which focused on detailed engineering and construction of topsides and platform jackets.

The company and co-owners of Hebron announced project sanction in the fourth quarter of 2012, for which Suncor has a 22.729% interest. Growth spending for Hebron was $200 million in 2012, which focused on engineering, site preparation, and the start of construction of the gravity-based structure.

Other growth capital included development drilling for Hibernia, White Rose, Terra Nova and Buzzard, and for North America Onshore in the Cardium oil formation in Western Canada, which started producing late in 2012.

During 2012, Suncor participated in two exploration wells offshore Norway: the second appraisal well for the Beta discovery and the first exploration well for the PL 477 licence, known as Cooper. The wells were deemed to be dry holes; therefore, the related exploration expenditures were expensed in 2012. For the Beta discovery, the company will continue to evaluate the prospect, and plans to acquire new seismic data in 2013 and participate in further appraisal drilling in 2014.

The company also participated in various exploration wells offshore the U.K. – including the Northern Terrace area of the Buzzard field and the Romeo prospect. The Northern Terrace well was successful while results for the Romeo well are currently being evaluated.

Sustaining capital expenditures focused primarily on the planned maintenance programs for East Coast Canada assets, including the replacement of the FPSO water injection swivel and subsea infrastructure at Terra Nova, and the propulsion system for the White Rose FPSO.

Other Capital Expenditures

Refining and Marketing spent $643 million on capital expenditures in 2012, largely focused on planned maintenance at the Sarnia and Commerce City refineries, and the lubricants plant. The company also completed the project to reduce benzene content in gasoline production at the Commerce City refinery.

Significant Growth Projects Update

	Description	Current Cost Estimate ($ millions)	Project Spend to Date ($ millions)	Target Completion	Estimated % Complete Engineering	Estimated % Complete Construction
Operated						
Firebag Stage 4	62.5 mbbls/d bitumen	1 668	1 634	Q1 2013	100	99
Non-operated [1]						
Golden Eagle [2]	18.7 mboe/d (net)	1 000 (±10%)	280	Q4 2014/ Q1 2015		
Hebron [2]	34.2 mboe/d (net)	3 185 (±10%)	306	Q4 2017		

(1) Estimated completion percentages not provided for non-operated projects. Cost estimates are based on the most recent estimate provided by the operator.

(2) Cost Estimate and Project Spend to Date figures do not include fair market value adjustments recorded as part of the merger with Petro-Canada in 2009.

The table above provides a review and update at December 31, 2012 of major growth projects that have been sanctioned for development by the company. Other growth projects, such as the Fort Hills and Joslyn North oil sands mining projects and the Voyageur upgrader project, have not yet received a final investment decision by the company or its Board of Directors and the respective owners of each of the individual projects. These projects are discussed under Other Capital Projects below.

Firebag Stage 4 is nearly complete and expected to be approximately 15% under the announced cost estimate of $2.0 billion. The company anticipates that bitumen production from Firebag will reach production capacity of 180,000 bbls/d over the next year.

The field development plan for the Golden Eagle Area Development includes stand-alone facilities designed for 70,000 boe/d of gross production. Activity in 2013 will focus on the completion and installation of platform jackets and wellhead topsides, followed by the start of development drilling. Capital expenditures for 2012 were $217 million, bringing total project expenditures to date to $280 million. The cost estimate of $1.0 billion has increased over the prior year primarily due to a change in the foreign exchange rate.

The co-owners for the Hebron project officially sanctioned development on December 31, 2012. The Hebron field includes a gravity-based structure design supporting an oil production rate of 150,000 bbls/d. The initial gross cost estimate for this project is $14 billion, of which Suncor's total project expenditures to date associated with the project scope are $306 million.

Other Capital Projects

Suncor also anticipates 2013 capital expenditures to be focused on the following projects and initiatives:

Oil Sands Base and In Situ

The company plans to focus growth capital efforts on optimizing the existing asset base by building new infrastructure to enhance marketing flexibility and takeaway capacity, and through the advancement of various debottlenecking projects in mining and extraction, and In Situ. These projects will be less capital intensive but are expected to result in high returns and efficiencies throughout the Oil Sands operations. The company has commenced a debottlenecking project at the MacKay River central processing facility, which is expected to increase production capacity to 38,000 bbls/d by 2015.

Sustaining capital includes planned maintenance events for the Upgrader 1 and Upgrader 2 facilities, a central processing facility at Firebag, and refurbishment of the Upgrader 1 hydrogen plant. Infrastructure and facilities to support the ongoing TRO$_{TM}$ process will continue in 2013.

Suncor plans to focus on the completion of the well pads in Firebag Stage 4, and continue infill well programs and development drilling in Firebag and MacKay River to maintain an inventory of future bitumen supply as production from older wells experience natural declines.

Oil Sands Ventures

Capital expenditures in 2013 for Syncrude are expected to focus on the mine train replacement for the Mildred Lake mining area, the mine train relocation at the Aurora mining area and sustaining maintenance initiatives.

Suncor continues to work closely with co-owners on evaluating and progressing Oil Sands Venture growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.

The partners of the Fort Hills mining project expect to reach a sanction decision in the second half of 2013.

Subject to the owners sanctioning the project, post sanction activities are expected to include the commencement of detailed engineering design, bulk equipment and material procurement, and site construction.

Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn project when available. Design engineering and site preparation activities will be a continued focus in 2013.

Suncor's view is that the economic outlook for the Voyageur upgrader project is challenged. Suncor and its partner continue to work diligently towards determining an outcome for the project. The partners have been considering options for the project, including the implications of cancellation or indefinite deferral. No formal decisions regarding the project have been made and the partners continue to work toward a decision by the end of the first quarter of 2013. The Voyageur upgrader project cannot be sanctioned to proceed without the approval of both partners and, in the case of Suncor, Suncor's Board of Directors. In the interim, Suncor and its partner have agreed to minimize expenditures on the project pending a decision.

Exploration and Production

In addition to Golden Eagle and Hebron, capital expenditures for Exploration and Production operations are expected to focus on development drilling for Terra Nova, Hibernia, White Rose and Buzzard, the procurement of subsea equipment for the development of the HSEU, development of the South White Rose Extension initially as an alternate gas storage site that will permit ongoing development and production, and reliability enhancement projects for Buzzard.

In the North Sea, the company will act as operator for a planned exploration well in licence P1658 (Block 20/05b) known as the Scotney prospect. In addition, the company plans to participate in two non-operated exploration wells in the U.K. and evaluate development options on the Buzzard Northern Terrace and CPZ areas in 2013.

The company is participating in two non-operated exploration wells in Norway in 2013. On the Beta licence, Suncor will continue to evaluate the prospect, and plans to acquire new seismic data in 2013 and participate in further appraisal drilling in 2014.

For North America Onshore operations, the company plans to continue developing its play in the Cardium oil formation in Western Canada and further delineate its play in the Kobes/Altares region of B.C. in the Montney shale gas formation.

Refining and Marketing

The company expects that sustaining capital will focus on planned maintenance events and routine asset replacement, and that growth capital is expected to be deployed on projects to prepare the Montreal refinery to receive shipments of western crude feedstock.

Renewable Energy

The company continues to progress the Adelaide and Cedar Point wind projects through the regulatory process in 2013. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

9. FINANCIAL CONDITION AND LIQUIDITY

Indicators

At December 31 ($ millions, except as noted)	**2012**	2011
Return on Capital Employed (%) (1)(2)		
Excluding major projects in progress	**7.3**	13.8
Including major projects in progress	**5.9**	10.1
Net debt to cash flow from operations (3) (times)	**0.7**	0.7
Interest coverage on long-term debt (times)		
Earnings basis (4)	**7.9**	10.7
Cash flow from operations basis (3)(5)	**17.6**	16.4

(1) Non-GAAP financial measure. The calculations for ROCE are detailed in the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The after-tax impairment of $1.487 billion for the Voyageur upgrader project impacted ROCE by approximately 4% in 2012.

(3) Cash flow from operations and metrics that use cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(5) Cash flow from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations, cash and cash equivalents, and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2013 capital spending program of $7.3 billion and meet current and long-term working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper and issuing long-term notes or debentures. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available to the company in debt capital markets at commercial terms and rates.

Cash and cash equivalents increased by $590 million to $4.393 billion during 2012, primarily due to strong cash flow from operations that exceeded capital expenditures, and the receipt of $300 million in risk mitigation proceeds related to the company's Syrian assets, partially offset by $1.451 billion of share repurchases, and $756 million in dividends. For the year ended December 31, 2012, the company's net debt to cash flow from operations measure was 0.7 times, which met management's target of less than 2.0 times.

Unutilized lines of credit at December 31, 2012 were $4.735 billion, compared to $4.428 billion at December 31, 2011.

A summary of available and utilized credit facilities is as follows:

At December 31, 2012 ($ millions)	
Fully revolving for a period of one year after term-out date (November 2013)	2 000
Fully revolving and expires in 2013-2014	924
Fully revolving for a period of four years and expires in 2016	3 000
Can be terminated at any time at the option of the lenders	379
Total available credit facilities	6 303
Less:	
Credit facilities supporting outstanding commercial paper	775
Credit facilities supporting standby letters of credit	793
Total unutilized credit facilities	4 735

Financing Activities

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

Suncor's interest on debt (before capitalized interest) in 2012 was $643 million, compared to $661 million in 2011. The reduction of short-term debt and the repayment of certain medium term notes in the third quarter of 2011 resulted in lower interest in 2012 compared to 2011, partially offset by the interest paid on two new finance leases in 2012.

Change in Net Debt

($ millions)	
Net debt – December 31, 2011	6 976
Decrease in net debt	(344)
Net debt – December 31, 2012	6 632
Decrease in net debt	
Cash flow from operations	9 745
Capital and exploration expenditures and Other investments	(6 962)
Proceeds from divestitures	68
Dividends less proceeds from exercise of share options	(568)
Repurchase of common shares	(1 451)
Change in non-cash working capital and other	(650)
Foreign exchange on cash, long-term debt and other balances	162
	344

At December 31, 2012, Suncor's net debt was $6.632 billion, compared to $6.976 billion at December 31, 2011. During 2012, net debt decreased by $344 million, largely due to cash flow from operations that exceeded capital and exploration expenditures, the receipt of $300 million in risk mitigation proceeds related to the company's Syrian assets, the impact of the strengthening Canadian dollar relative to the U.S. dollar on the valuation of long-term debt, partially offset by cash returned to shareholders in the form of share repurchases and dividends, and an increase in non-cash working capital.

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 60% of its total debt plus shareholders' equity. At December 31, 2012, total debt to total debt plus shareholders' equity was 22% (December 31, 2011 – 22%). The company is also currently in compliance with all operating covenants.

At December 31 ($ millions, except as noted)	2012	2011
Short-term debt	**776**	763
Current portion of long-term debt	**311**	12
Long-term debt	**9 938**	10 004
Total debt	**11 025**	10 779
Less: Cash and cash equivalents	**4 393**	3 803
Net debt	**6 632**	6 976
Shareholders' equity	**39 223**	38 600
Total debt plus shareholders' equity	**50 248**	49 379
Total debt to total debt plus shareholders' equity (%)	**22**	22

Short-Term Investments

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio will not exceed six months, and all investments will be with counterparties with investment grade debt ratings. As at December 31, 2012, the weighted average term to maturity of the short-term investment portfolio was approximately 30 days. In 2012, the company earned approximately $32.0 million of interest income on this portfolio.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions, and may require the company to post additional collateral under certain contracts.

The company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	BBB+	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investor Services	Baa1	Stable

The company's commercial paper ratings are:

Commercial Paper	Cdn$ Rating	US$ Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	Not rated
Moody's Investors Service	Not rated	P-2

In 2012, Moody's Investors Service upgraded the company's long-term senior debt rating from Baa2 to Baa1, and changed its long-term outlook from positive to stable. All other credit ratings are consistent with 2011. Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2012 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

December 31, 2012 (thousands)	
Common shares	1 523 057
Common share options – exercisable and non-exercisable	47 366
Common share options – exercisable	29 879

As at February 22, 2013, the total number of common shares outstanding was 1,523,644,237, and the total number of exercisable and non-exercisable common share options outstanding was 75,233,036. Once exercisable, each outstanding common share option is convertible into one common share.

Share Repurchases

During the first quarter of 2012, the company obtained regulatory approval from the Toronto Stock Exchange (TSX) to recommence a Normal Course Issuer Bid (the 2011 NCIB) under which the company was authorized to purchase for cancellation up to an additional $1.0 billion of Suncor's common shares between February 28, 2012 and September 5, 2012.

For the 2011 NCIB, the company repurchased 33,032,400 shares during 2012 at an average price of $30.28 per share, for a total repurchase cost of $1.0 billion.

During the second quarter of 2012, the company obtained regulatory approval in Canada for a program to issue put options on the company's common shares as part of the 2011 NCIB. Under this program, Suncor was permitted to issue put options to a Canadian financial institution, which entitled the purchaser, on the expiry date of the relevant options, to sell to Suncor a specified number of Suncor common shares at a price agreed to on the date the options were issued.

The company received $1.3 million in premiums for issuing 1,250,000 put options. No shares were repurchased through the exercise of put options, as all options expired unexercised. Cash premiums received by Suncor for issuing the put options were recorded as an increase to shareholders' equity and netted against the cash paid for the purchase of common shares for cancellation. Premiums received by Suncor for issuing put options do not impact the company's earnings.

In the third quarter of 2012, the company obtained regulatory approval for another Normal Course Issuer Bid (the 2012 NCIB) with the TSX authorizing the purchase for cancellation of up to $1.0 billion of its common shares. The 2012 NCIB commenced on September 20, 2012 and will end no later than September 19, 2013. Pursuant to the 2012 NCIB, Suncor has agreed that it will not purchase more than 38,392,005 common shares, which represented approximately 2.5% of issued and outstanding common shares as at September 14, 2012. The company subsequently announced it had entered into an automatic purchase plan with a designated broker to allow for the repurchase of common shares during scheduled and unscheduled share-trading blackout periods. Shareholders may obtain a copy of the company's Notice of Intention to make a Normal Course Issuer Bid by contacting Investor Relations.

For the 2012 NCIB, the company repurchased 13,829,900 shares during 2012 at an average price of $32.68 per share, for a total repurchase cost of $452 million. Subsequent to December 31, 2012, the company had repurchased an additional 3,915,646 shares under the 2012 NCIB at an average price of $32.45 per share for a total repurchase cost of $127 million, as of February 22, 2013.

At December 31 ($ millions, except as noted)	**2012**	2011
Share repurchase activities (thousands of common shares)		
Shares repurchased directly	**46 862**	17 128
Shares repurchased through exercise of put options	**—**	—
	46 862	17 128
Share repurchase cost ($ millions)		
Repurchase cost	**1 452**	500
Option premiums received	**(1)**	—
	1 451	500
Weighted average repurchase price per share, net of option premiums (dollars)	**30.96**	29.19

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In addition to the enforceable and legally binding obligations quantified in the table presented below, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

		Payments Due by Period			
($ millions)	Total	2013	2014 to 2015	2016 to 2017	Thereafter
Fixed and revolving-term debt (1)	**19 950**	**1 662**	**1 543**	**1 112**	**15 633**
Finance lease payments	**2 487**	**94**	**189**	**189**	**2 015**
Decommissioning and restoration costs (2)	**8 154**	**413**	**779**	**694**	**6 268**
Operating lease agreements, pipeline capacity and energy services commitments	**13 721**	**1 572**	**2 276**	**1 697**	**8 176**
Exploration work commitments	**272**	**67**	**205**	**—**	**—**
Other long-term obligations (3)	**449**	**149**	**300**	**—**	**—**
Total	**45 033**	**3 957**	**5 292**	**3 692**	**32 092**

(1) Includes debt that is redeemable at Suncor's option and interest payments on fixed-term debt.

(2) Represents the undiscounted amount of obligations associated with land and tailings reclamation and site restoration and decommissioning costs.

(3) Includes the Libya ESPA signature bonus and merger consent, and Fort Hills purchase obligations. See the Accrued Liabilities and Other – Long-Term Financial Liabilities note to the 2012 audited Consolidated Financial Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's Refining and Marketing segment. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to the Related Party Disclosures note to the 2012 audited Consolidated Financial Statements.

Financial Instruments

Suncor periodically enters into derivative contracts for risk management purposes. The derivative contracts hedge risks related to purchases and sales of commodities, to manage exposure to interest rates and to hedge risks specific to individual transactions. For the year ended December 31, 2012, the pre-tax earnings impact for risk management activities was a gain of $1 million (2011 – pre-tax loss of $22 million).

The company's Energy Trading business uses crude oil, natural gas, refined product and other derivative contracts to generate net earnings. For the year ended December 31, 2012, the pre-tax earnings impact for Energy Trading activities was a gain of $246 million (2011 – pre-tax gain of $301 million).

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding – January 1, 2011	13	(87)	(74)
Fair value of contracts realized during the year	9	(248)	(239)
Changes in fair value during the year	(22)	301	279
Fair value of contracts outstanding – December 31, 2011	—	(34)	(34)
Fair value of contracts realized during the year	**(2)**	**(255)**	**(257)**
Changes in fair value during the year	**1**	**246**	**247**
Fair value of contracts outstanding – December 31, 2012	**(1)**	**(43)**	**(44)**

The fair value of derivatives are recorded in the Consolidated Balance Sheets as follows:

Fair value of derivative contracts at December 31 ($ millions)	2012	2011
Accounts receivable	**53**	37
Accounts payable	**(97)**	(71)
	(44)	(34)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Energy Trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in our 2012 audited Consolidated Financial Statements.

10. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

There were no changes to Suncor's significant accounting policies in 2012, which are described in note 3 to the December 31, 2012 audited Consolidated Financial Statements.

Recently Announced Accounting Standards

Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for most fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013. The company does not expect any changes to its fair value measurements; however, expanded disclosures on fair value measurements are required.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7 *Financial Instruments: Disclosures* and IAS 32 *Financial Instruments: Presentation* to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Retrospective application of amendments to IFRS 7 are effective for annual and interim periods starting on or after January 1, 2013. Retrospective application of amendments to IAS 32 are effective for annual periods starting on or after January 1, 2014, with earlier application permitted. The adoption of these amended standards is not expected to have a material impact on the company's financial statements; however, expanded disclosures on financial instruments that are offset in the Consolidated Balance Sheets will be required.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Items of Other Comprehensive Income* to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to net earnings. The amendment is required to be retrospectively adopted for periods beginning on or after July 1, 2012. The company does not expect a significant change to its presentation of items of other comprehensive income.

Scope of a Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statement*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. Arrangements that meet the definition of a joint venture are required to apply the equity method of accounting. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the guidance on separate financial statements. IAS 28 has also been amended to conform to the changes made in IFRS 10 and 11.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013. The company has identified two existing joint arrangements in the Refining and Marketing segment that will be required to change from proportionate consolidation to equity accounting as a result of IFRS 11. This change will not have a material impact to the consolidated financial statements, but will result in the netting of revenues and expenses (2012 – approximately $100 million and $90 million, respectively) for these entities into Other Income. In addition, the company's net investment in these entities will be presented in Other Assets.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits,* which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in other comprehensive income thereby eliminating the previous options that were available, changes the calculation and presentation of the interest cost component of annual pension expense and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013. The company anticipates a net incremental increase to expenses of approximately $50 million for 2012 as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization and depreciation of stripping costs in the production phase if an entity can demonstrate that it is probable that future economic benefits will be realized, the costs can be reliably measured and the entity can identify the component of the ore body for which access has been improved. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2013. The company does not anticipate significant impacts as a result of this interpretation as the company generally performs stripping activities that provide access to ore to be mined in the current period.

Critical Accounting Estimates and Judgments

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information.

Critical accounting estimates are those estimates that require management to make assumptions about matters that are highly uncertain at the time the estimate is made, and those estimates where changes in critical assumptions that are within a range of reasonably possible outcomes would have a material impact on the company's financial condition, changes in financial condition or financial performance.

Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's December 31, 2012 audited Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Certain measurements of depletion, depreciation, amortization, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. Although not reported as part of the company's 2012 audited Consolidated Financial Statements, these estimates of reserves and resources can have a significant impact on the Consolidated Financial Statements.

The estimation of reserves involves the exercise of professional judgment. Reserves and certain resources were evaluated or reviewed as at December 31, 2012 by qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Where possible assumptions reflect market and regulatory conditions existing at December 31, 2012, which could differ significantly from other points in time throughout the year or in future periods.

Oil and Gas Activities

The company is required to use judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

The costs of drilling exploratory wells are initially capitalized pending the evaluation of commercially recoverable resources. The determination that commercial resources have been discovered requires judgment. If a judgment is made that there are no commercially recoverable resources, the associated exploration costs are charged to exploration expense. Evaluation costs incurred when management is assessing whether there are commercially recoverable resources and designing development and front-end engineering plans are capitalized. Exploration and evaluation assets are subject to ongoing technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. When management is making this assessment, changes to project economics, quantities of resources, expected production techniques, unsuccessful drilling, and estimated production costs and projected capital expenditures are important factors. If a judgment is made that extraction of the resources is not commercially viable, the associated exploration and evaluation assets are impaired and charged to depreciation, depletion, amortization and impairment expense.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, the receipt of the appropriate approvals from regulatory bodies and the company's internal project approval processes. After an oil and gas property is reclassified to property, plant and equipment, all subsequent development costs are capitalized.

Impairment of Assets

A cash-generating unit (CGU) is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of the company's assets into CGUs requires significant judgment with respect to the integration between assets, the use of shared infrastructure, the existence of active markets for the company's products and the way in which management monitors operations.

At the end of each reporting period, the company is required to identify events or conditions that indicate that the net carrying value of a CGU might be impaired. Management uses judgment to determine if a specific event or condition is an indication of impairment for a CGU. If any such indication exists, the company must complete an impairment assessment for the CGU. A CGU is impaired when the net carrying value of the CGU exceeds management's estimate of the recoverable amount of the CGU, which is the higher of the CGU's fair value less costs to sell and its value-in-use.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment. For 2012, the company completed this review as at July 31, 2012, and determined that the underlying CGUs were not impaired.

At the end of each reporting period, the company must exercise judgment to determine if there are indicators that conditions causing a previous impairment have reversed. Where new estimates of recoverable amount exceed net carrying value, previously recorded impairment adjustments are reversed, up to the amount of the original impairment. An impairment of goodwill cannot be reversed.

For Suncor, the estimated recoverable amount of a CGU is predominantly determined using discounted net future cash flow models. The key assumptions the company uses for estimating future cash flows are estimates of future commodity prices, reserves and resources estimates, expected production volumes, estimated future operating and development costs, and estimated refining margins. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management. Management may also be required to make judgments about the likelihood of occurrence of a future event, which may have an impact on key assumptions. Changes to these estimates and judgments will affect the recoverable amount of a CGU and may require a material impairment to the net carrying value of that CGU.

The company also assesses the impairment of assets when they are classified as held for sale or when they are reclassified from Exploration and evaluation assets to Property, plant and equipment. Assets held for sale are measured at the lower of net carrying value and fair value less costs to sell, which may be determined based on expected sale proceeds.

The following discusses important impairment assessments completed during 2012:

Voyageur Upgrader Project

At December 31, 2012, Suncor's view was that the economic outlook for the Voyageur upgrader project was challenged and, therefore, performed an impairment test, resulting in an after-tax impairment charge of $1.487 billion. The net recoverable amount was estimated under a fair value less costs to sell methodology and determined using an expected cash flow approach.

Key assumptions included current forecasts for the price of commodities, an estimate of price realizations, estimates of future operating and capital expenditures, and an after-tax risk-adjusted discount rate of 10%. As at December 31, 2012, the company's carrying value for assets relating to the Voyageur upgrader project was approximately $345 million.

Syria

As a result of political unrest and international sanctions announced in December 2011, the company suspended its operations in Syria and ceased recording production or revenues. Suncor performed an impairment test on its assets in Syria at December 31, 2011 and determined that the assets were not impaired at that time.

As there had been no resolution of the political situation at the end of the second quarter of 2012, another impairment test on the company's Syrian assets was performed. As a result, the company recognized an after-tax impairment charge of $604 million against Property, plant and equipment, a write-down of receivables of $67 million and a write-down of $23 million against current assets.

During the fourth quarter of 2012, the company received risk mitigation proceeds of $300 million in respect of its Syrian operations. A portion, or all of these proceeds, may be repayable if operations in Syria resume and, therefore, were recorded as a provision in 2012 rather than to earnings. After receipt of the risk mitigation proceeds, an additional impairment test was performed at December 31, 2012, resulting in an after-tax impairment reversal of $177 million against assets in Syria.

The carrying value as at December 31, 2012 was based on a net recoverable amount that was estimated under a value-in-use methodology and determined using an expected cash flow approach, under probability weighted scenarios representing i) resumption of operations in one year, ii) resumption of operations in five years, and iii) total loss. The two scenarios where the company resumes operations incorporated repayment of the risk mitigation proceeds in accordance with the terms of the agreement.

Scenarios involving the company resuming normal operations used current forecasts for the price of commodities, the company's estimate of price realizations, estimates of operating and development expenditures based on the field development anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (19%) that represented management's best estimate of the ongoing risk involved with operating in Syria, and management's best estimate of the incremental rebuilding costs to bring operations back on-stream. Management's forecasts for production were based on the most recently available estimate of future production volumes evaluated by Suncor's internal qualified reserves evaluators. The resulting carrying value of the company's property, plant, and equipment in Syria net of the risk mitigation provision at December 31, 2012 was approximately $130 million.

Fair Value of Financial Instruments

To estimate the fair value of financial instruments, the company uses quoted market prices when available, or models that use observable market data. In addition to market information, Suncor incorporates transaction-specific details that market participants would use in a fair value measurement, including the impact of non-performance risk. Inputs used in determining fair value are characterized using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The company's estimate of fair value may differ from amounts that could be realized or settled in a current market transaction.

Provisions for Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment. Management applies judgment in assessing the existence and extent of the company's decommissioning and restoration obligations at the end of each reporting period, as well as in determining whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying Suncor's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in prices. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

The fair value of these provisions is estimated by discounting the expected future cash flows using the company's credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expenses, based on the discount rate.

Suncor's provision for decommissioning and restoration costs increased by $887 million in 2012 to $4.688 billion. The most significant change in the provision was with respect to the revised future cost estimates and increased disturbance. The provision also increased due to a decrease in the average discount rate (2012 – 3.75%; 2011 – 4.3%).

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, expected future cash flows and discount rates.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2012, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Employee Future Benefits

The company provides benefits to employees and retired employees, including pensions and other post-retirement benefits.

The obligations and costs of defined benefit pension and other post-retirement benefit plans are determined based on actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include estimates of, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. The accrued net benefit liability is reported as other long-term liabilities in the Consolidated Balance Sheets.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high-quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented. Actuarial gains and losses are recognized in other comprehensive income in the Consolidated Statements of Comprehensive Income in the period incurred.

Control and Significant Influence

Control is defined as the power to govern the financial and operating decisions of an entity so as to obtain benefits from its activities and significant influence is defined as the power to participate in the financial and operating decisions of the investee. The assessment of whether the company has control, joint control, or significant influence over another entity requires judgment of the impact it has over the financial and operating decisions of the entity and the extent of the benefits it obtains.

Income Taxes

The determination of the company's income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make other judgments, including those about deferred income taxes that are discussed below.

Management believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

In January 2013, the company received a proposal letter from the Canada Revenue Agency (CRA) relating to the income tax treatment of realized losses in 2007 on the settlement of the Buzzard derivative contracts. The company strongly disagrees with the CRA's position and will respond to the proposal letter; however, the CRA may proceed to issue a notice of reassessment (NOR) to increase the amount payable by approximately $1.2 billion. The company firmly believes it will be able to successfully defend its original filing position so that ultimately no increased income tax payable will result from the CRA's actions. However, notwithstanding the filing of an objection to dispute this matter, the company would be required to make a minimum payment of 50% of the amount payable under the NOR, estimated to be $600 million, which would remain on account until the dispute is resolved.

Deferred Income Taxes

A taxable or a deductible temporary difference may exist when there is a difference between the carrying value of an asset or liability and its respective tax basis. The reversal of deductible temporary differences results in deductible amounts when determining taxable income in future periods. The reversal of taxable temporary differences results in taxable amounts when determining taxable income of future periods.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

11. RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to its assets, activities and operations. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of our businesses or functions to meet or support a Suncor objective. Risks facing Suncor's business are listed below.

Volatility of Commodity Prices and Light/Heavy Differentials

Our financial performance is closely linked to prices for crude oil in our upstream business and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream business, where natural gas is both an input and output of production processes. The values for all of these commodity prices can be influenced by global and regional supply and demand factors.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), pipeline constraints, regional and international supply and demand imbalances, political developments, compliance or non-compliance with quotas imposed on Organization of Petroleum Exporting Countries (OPEC) members, access to markets for crude oil and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Suncor anticipates higher production of bitumen in future years, due mainly to production growth from Firebag. Due to its low viscosity, bitumen is blended with a light diluent or SCO and sold as a heavy crude oil. The markets for heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes and imbalances (whether as a result of pipeline constraints or otherwise). Heavy crude oil generally receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield, and the higher cost to transport the more viscous product on pipelines, and this price differential can be amplified due to supply and demand imbalances, as has been experienced over the last twelve months, due primarily to pipeline constraints and the inability to efficiently bring products to market. The price differential between light crude and WCS is particularly important for Suncor. The market price for WCS is influenced by regional supply and demand factors, including the availability and price of diluent, and by the availability and cost of accessing primary markets through pipeline systems. For the reasons noted above, the price differential between light crude and WCS in 2012 was at its widest level since 2008. Future light/heavy differentials are uncertain and continued widening of these light/heavy differentials could have a negative impact on our business, especially price realizations for WCS and bitumen that Suncor is unable to upgrade or process at its refineries.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources. All of these factors are beyond our control and can result in a high degree of price volatility.

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term. Constrained market access for oil sands production due to insufficient pipeline takeaway capacity, growing inland production and refinery outages create risk of widening differentials or shut-in of production that could have a material adverse effect on our business, financial condition, results of operations and cash flow. In addition, oil and natural gas producers in North America, and particularly in Canada, currently receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and natural gas producers such as Suncor. A prolonged period of low prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production from some properties and/or the impairment of that property's carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow, and may also lead to impairments or write-offs of the values of Suncor's assets or projects in development.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of greenhouse gas (GHG) and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields and mine sites (including restrictions on production), and possibly expropriation or cancellation of contract rights.

Changes in government policy or regulation, or interpretation thereof, have a direct impact on Suncor's business, financial condition, results of operations and cash flow, as evidenced by such initiatives as the Alberta government's royalty review program in 2007, and, more recently, by trade sanctions in Libya (which have since been lifted) and Syria imposed by Canadian and other international governments, and increased production taxes in the U.K. Changes in government policy or regulation can also have an indirect impact on Suncor, including opposition to new North American pipeline systems, such as the Keystone XL or the Northern Gateway proposals, or incrementally over time, through increasingly stringent environmental regulations or unfavourable income tax and royalty regimes. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other principal risks of Suncor, including environmental or safety non-compliance and permit approvals.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on our business, financial condition, results of operations and cash flow by impacting the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor. The company anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Failure to comply with environmental regulation may result in the imposition of significant fines and penalties, liability for cleanup costs and damages, and the loss of important licences and permits, which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow. Through industry associations, Suncor participates, both directly and indirectly, in the consultation process for the design of proposed regulations and other efforts to harmonize regulations across jurisdictions within North America.

Some of the issues that are or may in future be subject to environmental regulation include:

- The possible cumulative regional impacts of oil sands development;
- The manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- The need to reduce or stabilize various emissions to air;
- Withdrawals, use of, and discharges to water;
- The use of hydraulic fracturing to assist in the recovery and production of oil and natural gas;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions;
- U.S. state or federal calculation and regulation of fuel life-cycle carbon content; and
- Regulation or policy by foreign governments or other organizations to limit purchases of oil produced from unconventional sources, such as the oil sands.

Climate Change Regulation

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements; however, Suncor expects the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the intensity of its GHG emissions, the absolute GHG emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

As part of its ongoing business planning, Suncor assesses potential costs associated with carbon dioxide (CO_2) emissions in its evaluation of future projects, based on the company's current understanding of pending and possible GHG regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. In the future, the company expects that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on its strategy, using a price range of $15-$60 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

The Canadian federal government has indicated a preference for a sector-specific approach to climate change regulation; however, it is unclear what form any regulation will take for the oil and gas sector, and what type of compliance mechanisms will be available to large emitters. At this time, the company does not believe it is possible to predict the nature of any requirements or the impact on Suncor's business, financial condition, results of operations and cash flow. The impact of developing regulations cannot be quantified at this time in the absence of detail on how systems will operate.

Although Suncor does not actively market into California, the implications of other states or countries adopting similar Low Carbon Fuel Standard (LCFS) legislation could pose a significant barrier to its exports of oil sands crude if the importing jurisdictions do not acknowledge efforts undertaken by the oil sands industry to meet the emissions intensity reductions legislated by the Government of Alberta.

Land Reclamation

There are risks associated specifically with the company's ability to reclaim tailings ponds containing mature fine tailings, with TRO_{TM} or other methods and technologies. Suncor expects that TRO_{TM} will help the company reclaim existing tailings ponds by reducing tailings. The success of TRO_{TM} or any other methods of technology and the time to reclaim tailings ponds could increase or decrease Suncor's decommissioning and restoration cost estimates. The company's failure or inability to adequately implement its reclamation plans could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Alberta's Land-Use Framework

Alberta's Land-Use Framework (LUF) has been implemented under the Alberta Land Stewardship Act (ALSA), which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licences, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan (LARP), the first regional plan under the LUF. The LARP identifies management frameworks for air, land, water and biodiversity that will incorporate cumulative limits and triggers, as well as identifying areas related to conservation, tourism and recreation.

The implementation of, and compliance with the terms of, the LARP may adversely impact our current properties and projects in northern Alberta due to, among other things, environmental limits and thresholds. Due to the cumulative nature of the plan, the impact of the LARP on Suncor's operations may be outside of the control of the company, as Suncor's operations could be impacted as a result of restrictions imposed due to the cumulative impact of development in the area, and not solely in relation to Suncor's direct impact.

Alberta Environment Water Licences

We currently rely on fresh water, which is obtained under licences from Alberta Environment, to provide domestic and utility water at our Oil Sands operations. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that the company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the company's projects relies on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted on terms favourable to Suncor, or at all, or that such additional water will in fact be available to divert under such licences.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs, by changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. Some of the issues where settlement with regulatory bodies may cause royalties expense or royalties payable to differ materially from provisions currently recorded include:

- For Suncor's Oil Sands Base mining operations, the Suncor BVM is based on the terms of the Suncor Royalty Amending Agreement (RAA), which modifies the application of the Suncor BVM as recently enacted by requiring additional quality and transportation adjustments. Suncor has filed non-compliance notices with the Alberta government, citing that reasonable quality adjustments in the determination of the Suncor BVM were not considered by the Alberta government as permitted by the Suncor RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The co-owners of Syncrude have also filed a non-compliance notice in respect of the determination of the bitumen value under its 2008 agreements with the Alberta government.

- Suncor has also appealed the disallowance of certain costs under the New Royalty Framework in Alberta and certain costs under royalty agreements in Newfoundland and Labrador, such as insurance premiums.

The final determination of these matters may have a material impact on royalties payable to the respective governments and on the company's royalties expense.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks and other uncertainties arising from foreign government sovereignty over the company's international operations, which may include, among other things:

- Currency restrictions and exchange rate fluctuations;
- Loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks;
- Increases in taxes and governmental royalties;
- Compliance with existing and emerging anti-corruption laws, including the Foreign Corrupt Practices Act of the United States, the Corrupt Foreign Officials Act of Canada and the United Kingdom Bribery Act;
- Renegotiation of contracts with governmental entities and quasi-governmental agencies, including risks around the current negotiations with the National Oil Company on the period in which Suncor was in force majeure under its EPSAs.
- Changes in laws and policies governing operations of foreign-based companies; and
- Economic and legal sanctions (such as restrictions against countries experiencing political violence, or countries that other governments may deem to sponsor terrorism).

If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. In addition, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

In response to international sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Since this time, the company's prospects for resuming operations in Syria have not improved. As a result, Suncor recorded impairment charges against its assets in Syria during 2012. There is no assurance as to if or when Suncor's operations in Syria will resume or return to previous levels.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or collateral damage of, an act of terror, political violence or war. Suncor may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that Suncor will be successful in protecting itself against these risks and the related financial consequences.

Operational Outages and Major Environmental or Safety Incidents

Each of Suncor's primary operating businesses – Oil Sands, Exploration and Production, and Refining and Marketing – demand significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carry the additional economic risk associated with operating reliably or enduring a protracted operational outage. These businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, civil suits or charges against the company.

Generally, Suncor's operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions, and the migration of harmful substances such as oil spills, gaseous leaks, or a release of tailings into water systems, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment, the environment, and information technology systems and related data and control systems.

The reliable operation of production and processing facilities at planned levels and Suncor's ability to produce higher value products can also be impacted by failure to follow operating procedures or operate within established operating parameters, equipment failure through inadequate maintenance, unanticipated erosion or corrosion of facilities, manufacturing and engineering flaws, and labour shortage or interruption. The company is also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of Suncor's business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. In addition, the unavailability of the information systems or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased operating costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security could adversely affect our business and results of operations.

In addition, some of Suncor's operations are subject to all of the risks connected with transporting, processing and storing crude oil, natural gas and other related products. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers may limit our availability to deliver feedstock. All of these events could have negative implications on sales and cash from operating activities.

For Suncor's Oil Sands operations, mining oil sands ore, extracting bitumen from mined ore, producing bitumen through in situ methods, and upgrading bitumen into SCO and other products involve particular risks and uncertainties. Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products, due to the interdependence of its component systems. Through growth projects, the company expects to further mitigate adverse impacts of interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, the company expects the MNU will stabilize secondary upgrading processes by providing flexibility during planned or unplanned maintenance.

For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of H_2S), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks.

Suncor's Exploration and Production operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes and other extreme weather conditions. Drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The consequence of catastrophic events, such as blow-outs, occurring in offshore operations can be more difficult and time-consuming to remedy. The occurrence of these events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Successful remediation of these events may be adversely affected by the water depths, pressures and cold temperatures encountered in the ocean, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate technology to resolve the event. Damage to the environment, particularly through oil spillage or extensive, uncontrolled fires or death, could result from these offshore operations. Suncor's offshore operations could also be affected by the actions of Suncor's contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to the company's equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations.

In particular, East Coast Canada operations can be impacted by winter storms, pack ice, icebergs and fog. During the winter storm season (October to March), the company may have to reduce production rates at its offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. During the spring, pack ice and icebergs drifting in the area of our offshore facilities have resulted in precautionary shut in of FPSO production and drilling delays. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter. In 2012, harsh weather conditions delayed the company's efforts to reconnect flow lines to drill centres for Terra Nova subsequent to a dockside maintenance program for the FPSO.

Suncor's Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other distribution facilities and service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. Although the company maintains a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from offshore operations. Suncor also has a captive insurance entity to provide additional business interruption coverage for potential losses.

Environment Health and Safety (EH&S) Regulatory Non-Compliance

The company is required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, some of which are described in the Industry Conditions – Environmental Regulation section of the 2012 AIF. Failure to comply with these regulations may result in the imposition of fines and penalties, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on our business, financial condition, results of operations and cash flow. Compliance can be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Project Execution

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base, the occurrence of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project execution risk consists of three related primary risks:

- Engineering – a failure in the specification, design or technology selection;
- Construction – a failure to build the project in the approved time and at the agreed cost; and
- Commissioning and start-up – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Management believes the execution of major projects presents issues that require prudent risk management. Suncor may provide cost estimates for major projects at the conceptual stage, prior to commencement or completion of the final scope design and detailed engineering necessary to reduce the margin of error of such cost estimates. Accordingly, actual costs can vary from estimates, and these differences can be material. Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- The impact of general economic, business and market conditions;
- The impact of weather conditions;
- Our ability to finance growth if commodity prices were to decline and stay at low levels for an extended period;
- Risks relating to restarting projects placed in safe mode, including increased capital costs; and
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment.

In addition, there are certain risks associated with the execution of our exploration, production and refining projects. These risks include, but are not limited to:

- Our ability to obtain the necessary environmental and regulatory approvals;

- Risks relating to scheduling, resources and costs, including the availability and cost of materials, equipment and qualified personnel;
- The impact of general economic, business and market conditions;
- The impact of weather conditions;
- The accuracy of project cost estimates;
- Our ability to finance growth;
- Our ability to source or complete strategic transactions;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment; and
- The commissioning and integration of new facilities within our existing asset base could cause delays in achieving guidance, targets and objectives.

The failure to sanction or build a project could result in additional costs, including abandonment and reclamation costs, to shut down the project, and such costs could be material to Suncor.

Corporate Reputation

The public perception of integrated oil and gas companies and their operations may pose issues related to development and operating approvals or market access for products, which may have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Development of the oil sands has figured prominently in recent political, media and activist commentary on the subjects of pipeline transportation, climate change, GHG emissions, water usage and environmental damage, which may directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- Creating significant regulatory uncertainty that challenges economic modelling of future projects and potentially delays sanctioning;
- Motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment; and
- Compelling legislation or policy that limits the purchase of crude oil produced from the Athabasca oil sands by governments and other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns such as those raised above may also harm our corporate reputation and limit our ability to transport our products or access land and joint arrangements in other jurisdictions throughout the world. Investors may respond by applying a discount to Suncor's shares, thereby diminishing the company's value, or may hinder Suncor in its ability to influence government policy.

Permit Approvals

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project.

Failure to obtain regulatory approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Skills and Resource Shortage

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high-quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to the growth of the oil sands industry. The increasing age of our existing workforce adds further pressure to this situation. Materials may also be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to balance these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate screening of project requests or consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that these objectives may exceed Suncor's capacity to adopt and implement change.

Cost Management

Production from oil sands through mining, upgrading and in situ recovery is, relative to most major conventional hydrocarbon reserves, a higher cost resource to develop and produce. Suncor is exposed to the risk of escalating operating costs, in both its oil sands business and other businesses which could reduce profitability and cash flow that might otherwise be directed towards growth or dividends, and major project capital costs, which could constrain Suncor's ability to execute high-quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage, the long-term success of existing and new in situ technologies, and the geology and reserves characterization of in situ reserves that can lead to higher steam-to-oil ratios and lower production.

Co-owner Management

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects where other entities operate assets in which Suncor has ownership or other interests. Suncor's dependence on its co-owners and its constrained ability to influence operations and associated costs could materially adversely affect Suncor's business, financial condition, results of operations and cash flow. The success and timing of Suncor's activities on assets and projects operated by others, or developed jointly with others, depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These co-owners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting joint arrangements may require agreement among the co-owners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While the partners generally seek consensus with respect to major decisions concerning the direction and operation of the assets and the development of projects, no assurance can be provided that the future demands or expectations of the parties relating to such assets and projects will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by all of the parties may affect our participation in the operation of such assets or in the development of such projects, our ability to obtain or maintain necessary licences or approvals, or the timing for undertaking various activities. In addition, disputes may arise pertaining to the timing and/or capital commitments with respect to projects that are being jointly developed, which could materially adversely affect the development of such projects and Suncor's business and operations.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our 2012 AIF / Form 40-F, filed with securities regulators.

12. OTHER ITEMS

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2012, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2012, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the year ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

As a result of past unrest in Libya and current events in Syria, Suncor is not able to monitor the status of all of its assets in these countries, including whether certain facilities have suffered damages. Suncor is continually assessing the control environment in these countries to the extent permitted by applicable law and does not consider the changes in these countries to have had a material impact on the company's overall internal control over financial reporting.

The effectiveness of our internal control over financial reporting as at December 31, 2012 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2012.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

13. NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in the MD&A – namely operating earnings, ROCE, cash flow from operations and Oil Sands cash operating costs – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Operating Earnings

Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. Operating earnings are reconciled to net earnings in the Consolidated Financial Information segment of the MD&A.

The following is a reconciliation of net earnings to operating earnings for Suncor's last five years of operations. Operating earnings for 2009 and 2008 are reported under Previous GAAP and have been adjusted from operating earnings previously reported to include the effect of project start-up costs and mark-to-market valuation of stock-based compensation, which were previously excluded when calculating operating earnings.

($ millions)	**2012**	2011	2010	2009	2008
Net earnings as reported	**2 783**	4 304	3 829	1 146	2 137
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)	(798)	852
Impairments and write-offs	**2 176**	629	306	42	—
Impact of income tax rate adjustments on deferred income taxes	**88**	442	—	4	—
Loss (gain) on significant disposals	**—**	107	(826)	39	—
Adjustments to provisions for assets acquired through the merger	**—**	31	68	97	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	—	(233)	499	(372)
Redetermination of working interests in Terra Nova	**—**	—	(166)	24	—
Modification of the bitumen valuation methodology	**—**	—	(51)	50	—
Merger and integration costs	**—**	—	79	151	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	(438)	—
Costs related to deferral of growth projects	**—**	—	—	299	
Operating earnings	**4 890**	5 674	2 634	1 115	2 617

Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in a particular section of the MD&A. This bridge analysis is presented because management uses this presentation to analyze performance.

The factor for Volumes is calculated based on production volumes and mix for the Oil Sands and Exploration and Production segments and sales volumes for the Refining and Marketing segment.

The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude.

The factor for Inventory reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory factor in a bridge analysis permits the company to present the factor for Volumes for upstream assets based on production volumes, rather than based on sales volumes.

The factor for Operating Expense includes transportation expense, project start-up costs, and operating, selling and general expense (adjusted for impacts of changes in inventory).

The factor for Financing Expense and Other Income includes financing expense, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates, and other income tax adjustments.

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. Average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

Year ended December 31 ($ millions, except as noted)		**2012**	2011	2010	2009	2008
Adjustments to net earnings						
Net earnings		**2 783**	4 304	3 829	1 146	2 137
Add after-tax amounts for:						
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt		**(157)**	161	(372)	(858)	852
Net interest expense		**41**	83	327	349	—
	A	**2 667**	4 548	3 784	637	2 989
Capital employed – beginning of twelve-month period						
Net debt		**6 976**	11 254	13 516	7 226	3 248
Shareholders' equity		**38 600**	35 192	32 485	14 523	11 896
	D	**45 576**	46 446	46 001	21 749	15 144
Capital employed – end of twelve-month period						
Net debt		**6 632**	6 976	11 254	13 377	7 226
Shareholders' equity		**39 223**	38 600	35 192	34 111	14 523
		45 855	45 576	46 446	47 488	21 749
Average capital employed (1)	B	**45 342**	44 956	46 075	35 128	18 447
ROCE – including major projects in progress (%)	A/B	**5.9**	10.1	8.2	1.8	16.2
Average capitalized costs related to major projects in progress	C	**8 729**	12 106	12 890	10 655	5 149
ROCE – excluding major projects in progress (%)	A/(B-C)	**7.3**	13.8	11.4	2.6	22.5

(1) For 2009 to 2012, average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. For 2008, average capital employed is calculated on the basis of a simple average (B+D)/2. This change in calculation was made as a result of the significant capital employed acquired in the merger with Petro-Canada in 2009. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Cash Flow from Operations

Cash flow from operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for fuel and income taxes, which management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Net earnings (loss)	**458**	2 603	1 520	**138**	306	1 938	**2 129**	1 726	819
Adjustments for:									
Depreciation, depletion, amortization and impairment	**3 964**	1 374	1 310	**1 857**	2 035	1 978	**468**	444	440
Deferred income taxes	**266**	895	487	**28**	354	196	**529**	494	269
Accretion of liabilities	**109**	85	130	**62**	69	103	**4**	3	2
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**—**	—	(316)	**—**	—	—	**(1)**	3	—
(Gain) loss on disposal of assets	**(29)**	122	14	**(1)**	31	(998)	**(13)**	(16)	(30)
Share-based compensation	**95**	(35)	55	**14**	(4)	24	**48**	(21)	39
Exploration expenses	**—**	—	—	**145**	28	96	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(380)**	(458)	(375)	**(32)**	(19)	(23)	**(21)**	(19)	(19)
Other	**(76)**	(14)	(48)	**16**	46	11	**7**	(40)	18
Cash flow from (used in) operations	**4 407**	4 572	2 777	**2 227**	2 846	3 325	**3 150**	2 574	1 538
(Increase) decrease in non-cash working capital	**(781)**	(676)	(890)	**(205)**	398	(320)	**(485)**	600	(260)
Cash flow provided by (used in) operating activities	**3 626**	3 896	1 887	**2 022**	3 244	3 005	**2 665**	3 174	1 278

	Corporate, Energy Trading and Eliminations			Total		
Year ended December 31 ($ millions)	**2012**	2011	2010	**2012**	2011	2010
Net earnings (loss)	**58**	(331)	(448)	**2 783**	4 304	3 829
Adjustments for:						
Depreciation, depletion, amortization and impairment	**161**	99	75	**6 450**	3 952	3 803
Deferred income taxes	**(80)**	(99)	(201)	**743**	1 644	751
Accretion of liabilities	**7**	—	—	**182**	157	235
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183	(426)	**(181)**	183	(426)
Change in fair value of derivative contracts	**11**	(43)	31	**10**	(40)	(285)
(Gain) loss on disposal of assets	**(1)**	(1)	39	**(44)**	136	(975)
Share-based compensation	**57**	(42)	(5)	**214**	(102)	113
Exploration expenses	**—**	—	—	**145**	28	96
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(433)**	(496)	(417)
Other	**(71)**	(12)	(49)	**(124)**	(20)	(68)
Cash flow from (used in) operations	**(39)**	(246)	(984)	**9 745**	9 746	6 656
Decrease (increase) in non-cash working capital	**572**	(80)	300	**(899)**	242	(1 170)
Cash flow provided by (used in) operating activities	**533**	(326)	(684)	**8 846**	9 988	5 486

The following is a reconciliation of cash flow from operations for Suncor's last five years of operations. Cash flow from operations for 2008 and 2009 are reported under Previous GAAP.

($ millions)	**2012**	2011	2010	2009	2008
Cash flow provided by operating activities	**8 846**	9 988	5 486	2 575	4 462
Increase (decrease) in non-cash working capital	**899**	(242)	1 170	224	(405)
Cash flow from operations	**9 745**	9 746	6 656	2 799	4 057

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are derived by adjusting Oil Sands segment operating, selling and general expense (a GAAP measure based on sales volumes) for i) costs pertaining to Syncrude operations; ii) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor, and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes; iii) excess power generated and sold that is recorded in operating revenue; and iv) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes.

Year ended December 31 ($ millions)	**2012**	2011	2010
Operating, selling and general expense	**5 375**	5 169	4 537
Syncrude operating, selling and general expense	**(513)**	(529)	(473)
Non-production costs [1]	**(338)**	(275)	(305)
Other [2]	**(129)**	(10)	32
Cash operating costs	**4 395**	4 355	3 791
Cash operating costs ($/bbl)	**37.05**	39.05	36.70

(1) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes.

(2) Other includes the impacts of changes in inventory valuation and operating revenues associated with excess power from cogeneration units.

Effective 2012, the calculation of Oil Sands cash operating costs has been updated to better reflect the ongoing cash cost of production, and prior period figures have been redetermined. The cost of natural gas feedstock for secondary upgrading processes, the cost of diluent purchased for transportation of product to markets, and non-cash costs related to the accretion of liabilities for decommissioning and restoration provisions are no longer included in cash operating costs. Certain cash costs relating to safety programs, which were previously considered non-production costs, are now included in cash operating costs. The following table reconciles amounts previously reported to those presented in this MD&A:

Year ended December 31 ($ millions)	**2011**	2010
Cash operating costs, as previously reported	4 479	3 990
Elements added to cash operating costs definition:		
Safety programs	33	18
Elements removed from cash operating costs definition:		
Natural gas feedstock for secondary upgrading processes	(53)	(49)
Accretion of liabilities	(64)	(93)
Purchased diluent	(40)	(75)
Cash operating costs, as restated in this MD&A	4 355	3 791
Cash operating costs, as previously reported ($/bbl)	40.20	38.65
Cash operating costs, as restated in this MD&A ($/bbl)	39.05	36.70

Impact of First-in, First-out Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a first-in, first-out inventory (FIFO) valuation methodology. For Suncor, this results in a disconnect between the sales prices for refined products, which reflect current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflect market conditions at the time when the feedstock was purchased. This lag between purchase and sale can be anywhere from several weeks to several months, and is influenced by the time to receive crude after purchase (which can be several weeks for foreign offshore crude purchases), regional crude inventory levels, the completion of refining processes, transportation time to distribution channels, and regional refined product inventory levels.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a last-in, first-out (LIFO) methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

Generally, during times of increasing crude prices, a FIFO inventory valuation positively impacts net earnings, compared with LIFO inventory valuation, as inventories purchased during periods of lower relative feedstock costs are replaced by inventories purchased during periods of higher relative feedstock costs. Conversely, during times of decreasing crude prices, FIFO inventory valuation generally negatively impacts net earnings, compared with LIFO inventory valuation, as inventories purchased during periods of higher relative feedstock costs are replaced by inventories purchased during periods of lower relative feedstock costs.

The company's estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology is a relatively simple calculation that replaces the FIFO-based costs of goods sold with an average purchase cost over the same period, and does not incorporate all of the elements of a more complex and precise LIFO inventory valuation methodology that an entity using U.S. GAAP might include. The company's estimate is not derived from a standardized calculation and, therefore, is unlikely to be comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

14. ADVISORY – FORWARD-LOOKING INFORMATION

The MD&A contains certain forward-looking information and forward-looking statements (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian and U.S. securities laws. Forward-looking statements and other information is based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may" and similar expressions.

Forward-looking statements in this MD&A include references to:

Suncor's expectations about production volumes and the performance of its existing assets, including that:

- *Production at Firebag will reach 180,000 bbls/d over the next year;*
- *The MNU will increase sweet SCO production capacity by approximately 10% and stabilize secondary upgrading processes by providing flexibility during maintenance;*
- *Production capacity at Hebron will be 150,000 bbls/d with first oil late in 2017;*
- *There will be an increase of gross installed capacity of 140 MW from the Adelaide and Cedar Point wind projects and an increase of production to 38,000 bbls/d by 2015 at the MacKay River central processing facility;*
- *First oil from newly steamed wells at Mackay River will occur in the first quarter of 2013; and*
- *Golden Eagle will achieve first oil in late 2014 or early 2015.*

The anticipated duration and impact of planned maintenance events, including that:

- *The refurbishment of the Upgrader 1 hydrogen plant will take place late in the first quarter of 2013, and is expected to be offline for approximately 14 weeks;*
- *The decrease in sweet SCO production during the refurbishment of the Upgrader 1 hydrogen plant will be partially offset by the additional hydrotreating capacity from the MNU;*
- *The maintenance event for the Upgrader 1 facility will take place in the second quarter of 2013, and is scheduled for approximately seven weeks, and that, within this outage, Suncor anticipates no production from Upgrader 1;*
- *Suncor will complete maintenance at one of the Firebag central processing facilities during the maintenance of the Upgrader 1 facility;*
- *Maintenance will take place in the third quarter of 2013 for Suncor's Upgrader 2 facilities, which is anticipated to have an impact on SCO production;*
- *The commissioning of the third drill centre at Terra Nova will take place in the third quarter of 2013;*
- *Routine annual maintenance will take place for Terra Nova, White Rose and Buzzard in the second and third quarters of 2013;*
- *Maintenance events at the Edmonton refinery on the heavy sour crude train will occur in the second quarter of 2013 for an expected duration of five weeks and on the sweet synthetic crude unit in the third quarter of 2013 for an expected duration of two weeks; and*
- *Maintenance at the Sarnia refinery for one of its crude units will take place in the third quarter of 2013 for an expected duration of six weeks.*

Suncor's expectations about capital expenditures, and growth and other projects, including:

- *Suncor's belief that Firebag Stage 4 will come in approximately 15% below the announced cost estimate of $2.0 billion;*

- *Growth capital for 2013 will be focused on high return projects;*
- *Growth capital in Refining and Marketing will be focused on projects to prepare the Montreal refinery to receive shipments of western crude feedstock;*
- *Sanctioning of the Fort Hills mining project will occur in the second half of 2013, and, if sanctioned and subject to approval, post sanction development activities will commence, including detailed engineering design, bulk equipment and material procurement and site construction;*
- *The first two of four new storage tanks in Hardisty, Alberta will be connected to the Enbridge Mainline system in 2013;*
- *The completion of an insulated pipeline to allow transport of bitumen without the requirement for additional diluent between Firebag and the company's Athabasca terminal starting in the second quarter of 2013;*
- *The acquisition of new seismic data in 2013 and appraisal drilling in 2014 at the Beta discovery;*
- *Cost estimates, target completion dates and project details provided in the Significant Growth Projects Update and Other Capital Projects sections of the MD&A; and*
- *Plans to leverage and extend the production life of existing offshore infrastructure, with drilling activities in areas adjacent to producing fields, such as the Hibernia Extension, the White Rose Extensions, and the Northern Terrace area for Buzzard.*

Suncor's strategy for 2013, including:

- *Suncor's plans to continue redevelopment of existing fields in Libya and resume exploration activities in the country;*
- *Plans for Suncor to focus on optimization of its current asset base in the Oil Sands through the development of new infrastructure that will enhance regional takeaway capacity and marketing flexibility in 2013, and debottlenecking projects that are expected to provide low cost efficiencies and higher outputs in Oil Sands operations;*
- *The company's portfolio of in situ technology projects, which is expected to drive improvements and efficiencies in current production and develop future opportunities, and the focus of this portfolio on subsurface and surface challenges;*
- *Operational excellence initiatives will continuously improve Suncor's plant utilization and workforce productivity in 2013;*
- *A decision being made on the Voyageur project by the end of the first quarter of 2013; and*
- *Suncor will focus in 2013 on bringing the Montreal refinery into the inland refining network, and plans to transport western crudes via rail to the refinery.*

Also:

- *The plan for Suncor to pursue opportunities to divest non-core properties in its North American Onshore operations that meet its financial objectives;*
- *Increased competition and fluctuating demand in key retail markets for Suncor's Refining and Marketing business is expected to be offset by growth in wholesale channels;*
- *The company's assessment in respect of the proposal letter received from the CRA relating to the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts relating to Buzzard and the company's belief that it will be able to successfully defend its original filing position so that, ultimately, no increased income tax payable will result from the CRA's action;*
- *The company's assessment of asset impairment in Syria, including the amounts recorded as impairment charges in 2012 and the carrying value of such assets as at December 31, 2012;*
- *The company's assessment of the situation in Libya, including the amounts recorded as impairment charges in 2011;*
- *Management's belief that Suncor will have the capital resources to fund its planned 2013 capital spending program of $7.3 billion and to meet current and long-term working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper, and issuing long-term notes or debentures, and that, if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates;*
- *Management's belief that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels;*
- *The company's expectations that the maximum weighted average term to maturity of its short-term*

investment portfolio will not exceed six months, and that all investments will be with counterparties with investment grade debt ratings; and

- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.*

Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors.

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate our Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance Oil Sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business, such as our current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and that operations in Syria continue to be impacted by sanctions or political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations *that represent employees at our refineries and distribution facilities.*

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of taxes or changes to fees and royalties, and changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third-party approvals outside of Suncor's control that are customary to transactions of this nature; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this MD&A, including under the heading Risk Factors, and the company's 2012 AIF dated March 1, 2013 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. and all related financial information contained in the Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles as contained within Part 1 of the Institute of Chartered Accountants Handbook. They include certain amounts that are based on estimates and judgments.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition, and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of the company's financial reporting.

The Audit Committee of the Board of Directors, currently composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditor to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditor any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent reserves consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resources estimates, and recommend their approval to the Board of Directors. The internal auditors and the external auditor, PricewaterhouseCoopers LLP, have unrestricted access to the company, the Audit Committee and the Board of Directors.

Steve. Williams

Steve W. Williams
President and Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 26, 2013

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2012, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2012. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2012 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.

Steve W. Williams
President and Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 26, 2013

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Suncor Energy Inc.

We have completed integrated audits of Suncor Energy Inc.'s 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2012. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Suncor Energy Inc. ("the Company"), which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2012 and December 31, 2011 and its financial performance and its cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited the Company's internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting.

Auditor's responsibility

Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the Company's internal control over financial reporting.

Definition of internal control over financial reporting

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

Inherent limitations

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

Opinion

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 26, 2013

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	**2012**	2011
Revenues and Other Income		
Operating revenues, net of royalties (note 6)	**38 208**	38 339
Other income (note 7)	**408**	453
	38 616	38 792
Expenses		
Purchases of crude oil and products	**17 101**	17 725
Operating, selling and general (notes 8 and 25)	**8 948**	8 424
Transportation	**685**	736
Depreciation, depletion, amortization and impairment (note 9)	**6 450**	3 952
Exploration	**309**	116
(Gain) loss on disposal of assets	**(44)**	136
Project start-up costs	**60**	163
Financing expenses (note 10)	**66**	471
	33 575	31 723
Earnings before Income Taxes	**5 041**	7 069
Income Taxes (note 11)		
Current	**1 515**	1 121
Deferred	**743**	1 644
	2 258	2 765
Net Earnings	**2 783**	4 304
Other Comprehensive Income (Loss)		
Foreign currency translation adjustment	**(16)**	230
Foreign currency translation reclassified to net earnings	**—**	14
Cash flow hedges reclassified to net earnings	**(1)**	—
Actuarial loss on employee retirement benefit plans, net of income taxes of $63 (2011 – $117)	**(177)**	(339)
Other Comprehensive Income (Loss)	**(194)**	(95)
Total Comprehensive Income	**2 589**	4 209
Per Common Share (dollars) (note 12)		
Net earnings – basic	**1.80**	2.74
Net earnings – diluted	**1.79**	2.67
Cash dividends	**0.50**	0.43

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

($ millions)	**December 31 2012**	December 31 2011
Assets		
Current assets		
Cash and cash equivalents (note 13)	**4 393**	3 803
Accounts receivable	**5 244**	5 412
Inventories (note 15)	**3 743**	4 205
Income taxes receivable	**799**	704
Total current assets	**14 179**	14 124
Property, plant and equipment, net (note 16)	**55 458**	52 589
Exploration and evaluation (note 17)	**3 284**	4 554
Other assets (note 18)	**320**	311
Goodwill and other intangible assets (note 19)	**3 128**	3 139
Deferred income taxes (note 11)	**80**	60
Total assets	**76 449**	74 777
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt (note 20)	**776**	763
Current portion of long-term debt (note 20)	**311**	12
Accounts payable and accrued liabilities	**6 469**	7 755
Current portion of provisions (note 23)	**856**	811
Income taxes payable	**1 170**	969
Total current liabilities	**9 582**	10 310
Long-term debt (note 20)	**9 938**	10 004
Other long-term liabilities (note 21)	**2 310**	2 392
Provisions (note 23)	**4 933**	3 752
Deferred income taxes (note 11)	**10 463**	9 719
Shareholders' equity	**39 223**	38 600
Total liabilities and shareholders' equity	**76 449**	74 777

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board of Directors:

Steve W. Williams
Director

Michael W. O'Brien
Director

February 26, 2013

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2012**	2011
Operating Activities		
Net earnings	**2 783**	4 304
Adjustments for:		
Depreciation, depletion, amortization and impairment	**6 450**	3 952
Deferred income taxes	**743**	1 644
Accretion	**182**	157
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183
Change in fair value of derivative contracts	**10**	(40)
(Gain) loss on disposal of assets	**(44)**	136
Share-based compensation	**214**	(102)
Exploration	**145**	28
Settlement of decommissioning and restoration liabilities	**(433)**	(496)
Other	**(124)**	(20)
(Increase) decrease in non-cash working capital (note 14)	**(899)**	242
Cash flow provided by operating activities	**8 846**	9 988
Investing Activities		
Capital and exploration expenditures	**(6 959)**	(6 850)
Acquisitions	**—**	(842)
Proceeds from disposal of assets	**68**	3 074
Proceeds from risk mitigation instruments	**300**	—
Other investments	**(3)**	(6)
(Increase) decrease in non-cash working capital (note 14)	**(51)**	26
Cash flow used in investing activities	**(6 645)**	(4 598)
Financing Activities		
Net change in short-term debt	**13**	(1 221)
Net change in long-term debt	**414**	(4)
Repayment of long-term debt	**—**	(500)
Issuance of common shares under share option plans	**188**	213
Purchase of common shares for cancellation, net of option premiums (note 24)	**(1 451)**	(500)
Dividends paid on common shares	**(756)**	(664)
Cash flow used in financing activities	**(1 592)**	(2 676)
Increase in Cash and Cash Equivalents	**609**	2 714
Effect of foreign exchange on cash and cash equivalents	**(19)**	12
Cash and cash equivalents at beginning of period	**3 803**	1 077
Cash and Cash Equivalents at End of Period	**4 393**	3 803
Supplementary Cash Flow Information		
Interest paid	**642**	672
Income taxes paid	**1 510**	885

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

($ millions)	Share Capital	Contributed Surplus	Foreign Currency Translation	Cash Flow Hedge	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2010	20 188	507	(451)	14	14 934	35 192	1 565 489
Net earnings	—	—	—	—	4 304	4 304	—
Foreign currency translation adjustment	—	—	244	—	—	244	—
Actuarial loss on employee retirement benefit plans	—	—	—	—	(339)	(339)	—
Total comprehensive income	—	—	244	—	3 965	4 209	—
Issued under share option plans	325	(57)	—	—	—	268	9 920
Issued under dividend reinvestment plan	12	—	—	—	(12)	—	355
Purchase of common shares for cancellation	(222)	—	—	—	(278)	(500)	(17 128)
Share-based compensation	—	94	—	—	—	94	—
Income tax benefit of stock option deduction in the U.S.	—	1	—	—	—	1	—
Dividends paid on common shares	—	—	—	—	(664)	(664)	—
At December 31, 2011	20 303	545	(207)	14	17 945	38 600	1 558 636
Net earnings	**—**	**—**	**—**	**—**	**2 783**	**2 783**	**—**
Foreign currency translation adjustment	**—**	**—**	**(16)**	**—**	**—**	**(16)**	**—**
Net change in cash flow hedges	**—**	**—**	**—**	**(1)**	**—**	**(1)**	**—**
Actuarial loss on employee retirement benefit plans	**—**	**—**	**—**	**—**	**(177)**	**(177)**	**—**
Total comprehensive income (loss)	**—**	**—**	**(16)**	**(1)**	**2 606**	**2 589**	**—**
Issued under share option plans	**255**	**(49)**	**—**	**—**	**—**	**206**	**10 804**
Issued under dividend reinvestment plan	**15**	**—**	**—**	**—**	**(15)**	**—**	**479**
Purchase of common shares for cancellation, net of option premiums (note 24)	**(609)**	**—**	**—**	**—**	**(842)**	**(1 451)**	**(46 862)**
Liability for share purchase commitment (note 24)	**(19)**	**—**	**—**	**—**	**(29)**	**(48)**	**—**
Share-based compensation	**—**	**83**	**—**	**—**	**—**	**83**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(756)**	**(756)**	**—**
At December 31, 2012	**19 945**	**579**	**(223)**	**13**	**18 909**	**39 223**	**1 523 057**

The accompanying notes are an integral part of the consolidated financial statements.

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and jointly controlled entities.

The address of the company's registered office is 150 - 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Canadian generally accepted accounting principles (GAAP) as contained within Part 1 of the Canadian Institute of Chartered Accountants Handbook.

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at February 26, 2013, the date the Board of Directors approved the statements.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these financial statements.

(c) Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the company's functional currency.

(d) Use of Estimates and Judgment

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgment used in the preparation of the financial statements are described in note 4.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interest in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities, and is a matter of judgment. Suncor recognizes its share of assets, liabilities, income and expenses, on a line-by-line basis, of its jointly controlled entities and jointly controlled assets. Investments in entities over which the company has significant influence are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities represent the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in Other Comprehensive Income.

If the company or any of its investments dispose of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net earnings.

(c) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. For operations not pursuant to production sharing contracts (PSCs), crude oil and natural gas sold below or above the company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues, while overlifts are recorded as a payable at market value with a corresponding decrease to revenues. Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to PSCs are reflected in the consolidated financial statements based on the company's working interest. Under the PSCs, the company pays all exploration costs and a contractual share of costs to develop and operate the concessions. Each PSC establishes the exploration, development and operating costs the company is required to fund and establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the company and the respective government. Cost Recovery Oil and Profit Oil are reported as revenue when the sale of product to a third party occurs. Revenue also includes income taxes paid on our behalf by our government joint venture partners.

(d) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments at the time of purchase.

(e) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy supply and trading operations are carried at fair value less costs to sell, and any changes in fair value are recognized within Other Income.

(f) Exploration and Evaluation Assets

The costs to acquire non-producing oil and gas properties or licences to explore, drill exploratory wells and the costs to evaluate the commercial potential of underlying resources, including related borrowing costs, are initially capitalized as Exploration and Evaluation assets. Certain exploration costs, including geological, geophysical, seismic, and sampling on oil sands properties, are charged to Exploration expense as incurred.

Exploration and evaluation assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the related capitalized costs are charged to net earnings.

When management determines with reasonable certainty that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is transferred to Property, Plant and Equipment.

(g) Property, Plant and Equipment

Property, Plant and Equipment are recorded at cost.

The costs to acquire developed or producing oil and gas properties and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install dedicated infrastructure, such as wellhead equipment and supporting assets, mine development, offshore platforms and subsea structures, are capitalized as oil and gas properties within Property, Plant and Equipment.

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, in situ processing facilities, power generation, utility plants, and natural gas processing plants, and all renewable energy, refining, distribution, marketing assets and related decommissioning and restoration obligations, are capitalized as Property, Plant and Equipment. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to the company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized.

Stripping activity required to access oil sands mining resources incurred in the initial development phase is capitalized as part of the investment in the construction cost of the mine. Stripping costs incurred in the production phase are charged to expense as they normally relate to production for the current period.

The costs of planned major inspection, overhaul and turnaround activities that maintain Property, Plant and Equipment and benefit future years of operations are capitalized. Recurring planned maintenance activities performed on shorter intervals are expensed as operating costs. Replacements outside of a major inspection, overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the company and the associated carrying amount of the replaced asset is derecognized.

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as finance lease assets within Property, Plant and Equipment. Costs for all other leases are recorded as operating expense as incurred.

Borrowing costs relating to assets that take a substantial period of time to construct are capitalized as part of the asset. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use, and is suspended when construction of an asset is ceased for extended periods.

(h) Depreciation, Depletion and Amortization

Exploration and Evaluation assets are not subject to depreciation, depletion and amortization, with the exception of certain exploration assets. Once transferred to Property, Plant and Equipment and commercial production commences, these costs are depleted on a unit-of-production basis over proved developed reserves with the exception of property acquisition costs which are depleted over proved reserves.

Capital expenditures associated with significant development projects are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties, and costs of dedicated infrastructure, such as wellhead equipment, offshore platforms and subsea structures, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves.

Major components of Property, Plant and Equipment are depreciated on a straight-line basis over their expected useful lives.

Natural gas processing plants and transportation assets	15 to 25 years
Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	30 to 40 years
Refineries, ethanol and lubricants plants	20 to 40 years
Marketing and other distribution assets	20 to 40 years

The costs of major inspection, overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next scheduled activity, which varies from two to five years.

Depreciation, depletion and amortization rates are reviewed annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

(i) Goodwill and Other Intangible Assets

The company accounts for business combinations using the acquisition method. The excess of the purchase price over the fair value of the identifiable net assets represents goodwill, and is allocated to the cash-generating units (CGUs) or groups of CGUs expected to benefit from the business combination.

Other intangible assets include acquired customer lists and brand value.

Goodwill and brand value have indefinite useful lives and are not subject to amortization. Customer lists are amortized over their expected useful lives, which range from five to ten years. Expected useful lives of goodwill and other intangible assets are reviewed on an annual basis.

(j) Impairment of Assets

Non-Financial Assets

Property, Plant and Equipment and Exploration and Evaluation assets are tested for indicators of impairment whenever events or changes in circumstance indicate that the carrying amount may not be recoverable. Exploration and Evaluation assets are also tested for impairment immediately prior to costs being transferred to Property, Plant and Equipment. Goodwill and intangible assets that have an indefinite useful life are tested at least annually for impairment.

If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell and value-in-use. In determining fair value less costs to sell, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

An impairment loss is recognized in Depreciation, Depletion, Amortization and Impairment for the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount.

Impairments are reversed for all CGUs and individual assets, other than goodwill, to the extent that events or circumstances give rise to changes in the estimate of recoverable amount since the period the impairment was recorded. Impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is evidence that a financial asset is impaired. If a financial asset carried at amortized cost is impaired, the amount of the loss is measured as the difference between the amortized cost of the loan or receivable and its recoverable amount. The loss is recognized in Operating, Selling and General expense.

(k) Assets Held For Sale

Assets and liabilities are classified as held for sale if their carrying amounts are expected to be recovered through a disposition rather than through continuing use. The assets or disposal groups are measured at the lower of their carrying amount and fair value less costs to sell. Impairment losses on initial classification as well as subsequent gains or losses on remeasurement are recognized in Depreciation, Depletion, Amortization and Impairment. However, when the assets or disposal groups are sold, the gains or losses on sale is recognized in (Gain) Loss on Disposal of Assets. Assets classified as held for sale are not depreciated, depleted or amortized.

(l) Provisions

Provisions are recognized by the company when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Provisions are recognized for decommissioning and restoration obligations associated with the company's Exploration and Evaluation assets and Property, Plant and Equipment. Provisions for decommissioning and restoration obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. The provision is accreted over time through charges to Financing Expenses with actual expenditures charged against the accumulated obligation. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes may be recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in earnings or in Other Comprehensive Income in the period they occur. Investment tax credits are recorded as an offset to the related expenditures.

(n) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans, defined contribution pension plans and other post-retirement benefits.

Company contributions to the defined contribution pension plans are expensed as incurred. The cost of the defined benefit pension plans and other post-retirement benefits is actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Costs, including the cost of pension benefits earned during the current year, the interest cost on pension obligations, and the expected return on pension plan assets, are recorded in Operating, Selling and General expense. Any actuarial gains or losses are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

The liability recognized on the balance sheet is the present value of the defined benefit obligations less the fair value of plan assets.

(o) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded in Operating, Selling and General expense.

Stock options that give the holder the right to purchase common shares are accounted for as equity-settled plans. The expense is based on the fair value of the options at the time of grant using the Black-Scholes options pricing model and is recognized over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus. Consideration paid to the company on exercise of options is credited to Share Capital and the associated amount in Contributed Surplus is reclassified to Share Capital.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model, with the exception of performance share units, which are measured at fair value using the Monte-Carlo simulation approach. The expense is recognized over the vesting period, with a corresponding adjustment to liabilities. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the Balance Sheet, net of any transaction costs (except for financial instruments classified as fair value through profit and loss, where transaction costs are expensed as incurred). Subsequent measurement of financial instruments is based on their classification:

Fair Value through Profit and Loss

Financial assets and liabilities that are held for trading or that are designated as fair value through profit and loss upon initial recognition. Changes in their fair value are recognized in earnings.

Loans and Receivables

Non-derivative financial assets, with fixed or determinable payments and are not quoted in an active market, are measured at amortized cost using the effective interest method.

Held-to-Maturity

Non-derivative financial assets that the company has the intent and ability to hold until maturity are measured at amortized cost using the effective interest method.

Other Financial Liabilities

Financial liabilities not classified as fair value through profit and loss are measured at amortized cost using the effective interest method.

Available for Sale

All other non-derivative financial assets are classified as available for sale, with changes in fair value recognized in Other Comprehensive Income.

The company classifies its derivative financial instruments (except those designated as effective hedging instruments) as fair value through profit and loss, its cash and cash equivalents and accounts receivable as loans and receivables, its financial instrument included in other assets as available for sale, and its accounts payable and accrued liabilities, debt, and other long-term liabilities as other financial liabilities.

The company uses derivative financial instruments, such as physical and financial contracts, either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program, or to earn trading revenues. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related operating segment. Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations.

Certain physical commodity contracts are deemed to be derivative financial instruments for accounting purposes. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract.

(q) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and in the fair value of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in Other Comprehensive Income and are recognized in earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings immediately. Changes in the fair value of a derivative designated in a fair value or cash flow hedge are recognized in the same line item as the underlying hedged item.

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects. When the company repurchases its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a deduction from Retained Earnings. Shares are cancelled upon purchase.

(s) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are declared by the company's Board of Directors.

(t) Earnings per Share

Basic earnings per share is calculated by dividing the net earnings for the period by the weighted-average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted-average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share if they have a dilutive impact in the period.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information. The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2012 by independent qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2012, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important judgments when making this determination.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to Property, Plant and Equipment. This decision considers several factors, including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval processes.

Determination of Cash Generating Units

A CGU is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs to sell or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, expected production volumes, future operating and development costs, discount rates, tax rates, and refining margins. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period.

Management also uses judgment to determine whether the nature of the activities performed are related to decommissioning and restoration activities or normal operating activities.

In addition, these provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to estimates related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, and estimates on timing and amount of expected future cash flows and discount rates.

Income Taxes

Management annually evaluates tax positions taken which could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered more likely than not. The company believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's judgment of the likelihood of a future outflow and estimates of the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

Control and Significant Influence

Control is defined as the power to govern the financial and operating decisions of an entity so as to obtain benefits from its activities and significant influence is defined as the power to participate in the financial and operating decisions of the investee. The assessment of whether the company has control, joint control, or significant influence over another entity requires judgment of the impact it has over the financial and operating decisions of the entity and the extent of the benefits it obtains.

Fair Value of Financial Instruments

The fair value of financial instruments is determined whenever possible based on observable market data. If not available, the company uses third-party models and valuation methodologies that utilize observable market data including forward commodity prices, foreign exchange rates and interest rates to estimate the fair value of financial instruments, including derivatives. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

Scope of a Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. Arrangements that meet the definition of a joint venture are required to apply the equity method of accounting. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the guidance on separate financial statements. IAS 28 has also been amended to conform to the changes made in IFRS 10 and 11.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted. The company has identified two existing joint arrangements in the Refining and Marketing segment that will be required to change from proportionate consolidation to equity accounting as a result of IFRS 11. This change will not have a material impact to the consolidated financial statements, but will result in the netting of revenues and expenses (2012 – approximately $100 million and $90 million, respectively) for these entities into Other Income. In addition, the company's net investment in these entities will be presented in Other Assets.

Financial Instruments: Recognition and Measurement

In November 2009, as part of the IASB project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for most fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not expect any changes to its fair value measurements; however, expanded disclosures on fair value measurements are required.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7 *Financial Instruments: Disclosures* and IAS 32 *Financial Instruments: Presentation* to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Retrospective application of amendments to IFRS 7 are effective for annual and interim periods starting on or after January 1, 2013 with earlier application permitted. Retrospective application of amendments to IAS 32 are effective for annual periods starting on or after January 1, 2014 with earlier application permitted. The adoption of these amended standards is not expected to have a material impact on the company's financial statements; however, expanded disclosures on financial instruments that are offset in the Consolidated Balance Sheets will be required.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Items of Other Comprehensive Income* to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to net earnings. The amendment is required to be retrospectively adopted for periods beginning on or after July 1, 2012. The company does not expect a significant change to its presentation of items of Other Comprehensive Income.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits,* which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in Other Comprehensive Income thereby eliminating the previous options that were available, changes the calculation and presentation of the interest cost component of annual pension expense and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company anticipates a net incremental increase to expenses of approximately $50 million for 2012 as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization and depreciation of stripping costs in the production phase if an entity can demonstrate that it is probable that future economic benefits will be realized, the costs can be reliably measured and the entity can identify the component of the ore body for which access has been improved. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The company does not anticipate significant impacts as a result of this interpretation as the company generally performs stripping activities that provide access to ore to be mined in the current period.

6. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services. The following summary describes the operations in each of the segments:

- Oil Sands includes the company's operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in Joslyn North (35.75%) and Fort Hills (40.8%) mining projects and the Voyageur upgrader (51%) project as well as its 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.

- Exploration and Production includes exploration and production of natural gas, crude oil and natural gas liquids in Western Canada, offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria.

- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through retail stations located in Canada and the United States (U.S.), as well as a lubricants plant located in Eastern Canada.

The company also reports activities not directly attributable to an operating segment under Corporate, Energy Trading and Eliminations. This includes investments in renewable energy projects.

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment balances are eliminated on consolidation. Intersegment profit will not be eliminated until the related product has been sold to third parties.

The company had no customer that individually represents 10% or more of the consolidated revenues for the year ended December 31, 2012 (2011 – one customer).

For the years ended December 31 ($ millions)	Oil Sands[1] 2012	Oil Sands[1] 2011	Exploration and Production 2012	Exploration and Production 2011	Refining and Marketing 2012	Refining and Marketing 2011	Corporate, Energy Trading and Eliminations 2012	Corporate, Energy Trading and Eliminations 2011	Total 2012	Total 2011
Revenues and Other Income										
Gross revenues	**8 378**	8 583	**5 947**	6 293	**26 109**	25 657	**89**	77	**40 523**	40 610
Intersegment revenues	**3 124**	3 420	**529**	491	**212**	56	**(3 865)**	(3 967)	**—**	—
Less: Royalties	**(684)**	(799)	**(1 631)**	(1 472)	**—**	—	**—**	—	**(2 315)**	(2 271)
Operating revenues, net of royalties	**10 818**	11 204	**4 845**	5 312	**26 321**	25 713	**(3 776)**	(3 890)	**38 208**	38 339
Other income	**20**	31	**71**	(3)	**27**	58	**290**	367	**408**	453
	10 838	11 235	**4 916**	5 309	**26 348**	25 771	**(3 486)**	(3 523)	**38 616**	38 792
Expenses										
Purchases of crude oil and products	**211**	383	**444**	585	**20 395**	20 547	**(3 949)**	(3 790)	**17 101**	17 725
Operating, selling and general	**5 375**	5 169	**795**	850	**2 286**	2 182	**492**	223	**8 948**	8 424
Transportation	**337**	399	**182**	116	**204**	219	**(38)**	2	**685**	736
Depreciation, depletion, amortization and impairment	**3 964**	1 374	**1 857**	2 035	**468**	444	**161**	99	**6 450**	3 952
Exploration	**71**	56	**238**	60	**—**	—	**—**	—	**309**	116
(Gain) loss on disposal of assets	**(29)**	122	**(1)**	31	**(13)**	(16)	**(1)**	(1)	**(44)**	136
Project start-up costs	**57**	163	**—**	—	**3**	—	**—**	—	**60**	163
Financing expenses	**127**	74	**81**	65	**5**	13	**(147)**	319	**66**	471
	10 113	7 740	**3 596**	3 742	**23 348**	23 389	**(3 482)**	(3 148)	**33 575**	31 723
Earnings (Loss) Before Income Taxes	**725**	3 495	**1 320**	1 567	**3 000**	2 382	**(4)**	(375)	**5 041**	7 069
Income taxes										
Current	**1**	(3)	**1 154**	907	**342**	162	**18**	55	**1 515**	1 121
Deferred	**266**	895	**28**	354	**529**	494	**(80)**	(99)	**743**	1 644
	267	892	**1 182**	1 261	**871**	656	**(62)**	(44)	**2 258**	2 765
Net Earnings (Loss)	**458**	2 603	**138**	306	**2 129**	1 726	**58**	(331)	**2 783**	4 304
Capital and Exploration Expenditures	**4 957**	5 100	**1 261**	874	**646**	633	**95**	243	**6 959**	6 850

(1) During the first quarter of 2012, the company completed a review of the presentation of purchase and sale transactions in its Oil Sands segment. It was determined that certain transactions previously recorded on a gross basis are more appropriately reflected through net presentation as the substance of the arrangement is an exchange of similar crude inventory rather than a sale that generates revenue.

Prior period comparative figures have been reclassified for comparability with the current period presentation. The impact is as follows:

($ millions, decrease)	2011
Gross revenues	998
Purchase of crude oil and products	998
Net earnings	—

Geographical Information

Operating Revenues, net of Royalties

($ millions)	2012	2011
Canada	**30 175**	30 878
Foreign	**8 033**	7 461
	38 208	38 339

Non-Current Assets[2]

($ millions)	Dec 31 2012	Dec 31 2011
Canada	**55 766**	53 794
Foreign	**6 424**	6 799
	62 190	60 593

(2) Excludes deferred income tax assets.

7. OTHER INCOME

Other Income consists of the following:

($ millions)	**2012**	2011
Energy trading activities		
Change in fair value of contracts	**246**	301
Unrealized losses on inventory valuation	**(13)**	(19)
Risk management activities	**1**	(22)
Investment and interest income	**80**	141
Renewable energy grants	**59**	64
Other	**35**	(12)
	408	453

8. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	**2012**	2011
Contract services	**4 069**	4 107
Employee benefit costs(1)	**2 697**	2 062
Materials	**725**	882
Energy	**613**	712
Equipment rentals and leases	**330**	363
Travel, marketing and other	**514**	298
	8 948	8 424

(1) The company incurred $3.2 billion of employee benefit costs for the year ended December 31, 2012 (2011 – $2.5 billion), of which $2.7 billion (2011 – $2.1 billion) was recorded as employee benefits in Operating, Selling and General expense. Employee benefits expense includes salaries, benefits and share-based compensation.

9. ASSET IMPAIRMENT

Oil Sands

During the fourth quarter of 2012, the company recognized after-tax impairment charges of $1.487 billion related to the Voyageur upgrader project in its Oil Sands business. As a result of the challenging economic outlook for the Voyageur upgrader project, an impairment test was performed at December 31, 2012, using a fair value less cost to sell methodology. The company used an expected future cash flow approach, with a risk-adjusted discount rate of 10% to perform the calculation. As at December 31, 2012, the company's carrying value for assets relating to the Voyageur upgrader project was approximately $345 million.

The impairment charges were recorded as part of Depreciation, Depletion, Amortization and Impairment expense.

Syria

In December 2011, the company declared force majeure under its contractual obligations, suspended its operations and ceased recording production due to political unrest and international sanctions affecting that country. An impairment test was performed at that time, which determined that the assets were not impaired.

As there had been no resolution of the political situation at the end of the second quarter of 2012, another impairment test was performed on the company's Syrian assets. As a result, the company recognized after-tax impairment charges and write-downs of $694 million. The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense and charged against Property, Plant and Equipment ($604 million) and other current assets ($23 million). The company also wrote off the remainder of its Syrian receivables ($67 million). A write-down of receivables of $64 million was previously recorded at December 31, 2011.

During the fourth quarter of 2012, the company received $300 million of risk mitigation proceeds related to its Syrian operations. The proceeds are subject to a provisional repayment should the company resume operations in Syria and therefore, have been recorded as a non-current provision at December 31, 2012.

After receipt of the risk mitigation proceeds, an impairment test was performed at December 31, 2012, using a value-in-use methodology. The company used an expected cash flow approach based on 2011 year-end reserves data updated for the company's best estimate of price realizations and remaining reserves, with three scenarios representing i) resumption of operations in one year, ii) resumption of operations in five years, and iii) total loss. The two scenarios where the company resumes operations incorporated repayment of the risk mitigation proceeds in accordance with the terms of the agreement. These scenarios were equally weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 19%. Based on this assessment, the company recognized an impairment reversal of $177 million related to Syrian assets in its Exploration and Production business.

The impairment reversal of $177 million was recorded in the fourth quarter of 2012 as part of Depreciation, Depletion, Amortization and Impairment expense. A 2% change in discount rates and a 5% change in pricing assumptions would each have an impact on after-tax earnings of approximately $20 million.

The resulting carrying value of the company's Property, Plant, and Equipment in Syria, net of the risk mitigation provision, at December 31, 2012 was approximately $130 million.

Libya

In the second quarter of 2011, the company recognized after-tax impairment charges of $514 million related to Libyan assets in its Exploration and Production business. At that time, production had been shut in due to political violence in Libya. The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense, and charged against Property, Plant and Equipment ($259 million), Exploration and Evaluation assets ($211 million), and Inventories ($44 million).

During the fourth quarter of 2011, the company reversed $11 million of the impairment charge that related to crude oil inventories. The reversal was the result of lifting certain political sanctions, and the joint venture partner confirming the existence of previously written off crude oil.

Production payments resumed in January 2012 with production in all major fields restarted in the first quarter of 2012. As a result, a valuation assessment was performed. The company used an expected cash flow approach based on 2012 year-end reserves data with a risk-adjusted discount rate of 17% to reflect uncertainty related to continued political unrest in the region, current production levels and the timing and success of future exploration drilling commitments. No reversal of impairment was recorded at December 31, 2012. A 2% change in discount rates would impact after-tax earnings by approximately $90 million while a 5% change in pricing assumptions would impact after-tax earnings by approximately $70 million.

The carrying value of Suncor's net assets in Libya as at December 31, 2012, net of asset impairment and write-offs, was approximately $650 million.

Other

During the fourth quarter of 2012, the company recognized an after-tax impairment charge of $65 million related primarily to certain East Coast Canada exploration and evaluation assets as well as natural gas Arctic land leases in the Exploration and Production business as a result of future development uncertainty. In addition, the company also recognized an after-tax impairment charge of $63 million related to CGUs in the Exploration and Production business due to a decline in price forecasts. The recoverable amount was determined using a fair value less cost to sell methodology, with the expected cash flow approach based on 2012 year-end reserves data and a risk-adjusted discount rate of 10%. A 2% increase in discount rates would decrease after-tax earnings by approximately $90 million while a 5% decrease in pricing assumptions would decrease after-tax earnings by approximately $30 million.

During the fourth quarter of 2011, the company recognized a charge of $100 million to reflect the write-down of certain natural gas CGUs in the Exploration and Production business to reflect the recoverable amount based on discounted cash flows.

The impairment charges were recorded as part of Depreciation, Depletion, Amortization and Impairment expense.

10. FINANCING EXPENSES

($ millions)	2012	2011
Interest on debt	**643**	661
Capitalized interest at 6.0% (2011 – 6.0%)	**(587)**	(559)
Interest expense	**56**	102
Accretion	**182**	157
Foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183
Foreign exchange and other	**9**	29
	66	471

11. INCOME TAXES

Income Tax Expense

($ millions)	2012	2011
Current:		
Current year	**1 483**	1 103
Adjustments for prior years	**32**	18
Deferred:		
Origination and reversal of temporary differences	**687**	1 258
Adjustments for prior years	**(32)**	(56)
Changes in tax rates and legislation	**88**	442
	2 258	2 765

There was no income tax recognized directly in equity during 2011 and 2012.

Reconciliation of Effective Tax Rate

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the difference is as follows:

($ millions)	2012	2011
Earnings before income tax	**5 041**	7 069
Canadian statutory tax rate	**25.67%**	27.19%
Statutory tax	**1 294**	1 922
Add (deduct) the tax effect of:		
Non-taxable component of capital gains and losses	**(22)**	(33)
Share-based compensation and other permanent items	**15**	34
Assessments and adjustments	**—**	(38)
Impact of income tax rate and legislative changes(1)	**88**	442
Canadian tax rate differential	**1**	(116)
Foreign tax rate differential	**763**	383
Non-taxable impairment charge	**127**	142
Other	**(8)**	29
	2 258	2 765

(1) In the second quarter of 2012, the Ontario government substantively enacted legislation to freeze the general corporate income tax rate at 11.5% instead of the planned reduction to 10%. Accordingly, the company recognized an increase in deferred tax expense of $88 million related to the revaluation of deferred income tax balances.

In the first quarter of 2011, the U.K. government substantively enacted a 12% increase in the supplementary charge on U.K. oil and gas profits. Accordingly, the company recognized an increase in deferred tax expense of $442 million related to the revaluation of deferred income tax balances.

Deferred Income Tax Balances

Deferred income tax expense and net liabilities in the company's financial statements were comprised of the following:

	Consolidated Statements of Comprehensive Income		Consolidated Balance Sheets (1)	
($ millions)	**2012**	2011	**Dec 31 2012**	Dec 31 2011
Property, plant and equipment	**1 266**	967	**11 991**	10 725
Decommissioning and restoration provision	**(625)**	205	**(1 132)**	(507)
Employee retirement benefit plans	**(55)**	73	**(636)**	(518)
Tax loss carry-forwards	**391**	(213)	**(167)**	(558)
Partnership deferral reserve	**(189)**	594	**405**	594
Other	**(45)**	18	**(78)**	(77)
	743	1 644	**10 383**	9 659

(1) The deferred income tax liability of $10.463 billion at December 31, 2012 (December 31, 2011 – $9.719 billion) includes $10.322 billion (December 31, 2011 – $9.713 billion) that will be settled beyond the next twelve months.

The deferred income tax asset of $80 million at December 31, 2012 (December 31, 2011 – $60 million) includes $71 million (December 31, 2011 – $47 million) that will be recovered beyond the next twelve months.

Change in Deferred Income Tax Balances

($ millions)	**2012**	2011
Beginning of year	**9 659**	7 842
Recognized in deferred income tax expense	**743**	1 644
Recognized in other comprehensive income	**(63)**	(117)
Foreign exchange and other	**44**	290
End of year	**10 383**	9 659

No deferred tax liability has been recognized at December 31, 2012 on temporary differences of approximately $10 billion (2011 – $9 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

In January 2013, the company received a proposal letter from the Canada Revenue Agency (CRA) relating to the income tax treatment of the realized losses in 2007 on the settlement of the Buzzard derivative contracts. The company strongly disagrees with the CRA's position and will respond to the proposal letter; however, the CRA may proceed to issue a notice of reassessment (NOR) to increase the amount payable by approximately $1.2 billion. The company firmly believes that it will be able to successfully defend its original filing position so that ultimately no increased income tax payable will result from the CRA's actions. However, notwithstanding the filing of an objection to dispute this matter, the company would be required to make a minimum payment of approximately 50% of the amount payable under the NOR, currently estimated to be $600 million, which would remain on account until the dispute is resolved.

12. EARNINGS PER COMMON SHARE

($ millions)	2012	2011
Net earnings	**2 783**	4 304
Dilutive impact of accounting for awards as equity-settled[1]	**(7)**	(86)
Net earnings – diluted	**2 776**	4 218
(millions of common shares)		
Weighted-average number of common shares	**1 545**	1 571
Dilutive securities:		
Effect of share options	**4**	11
Weighted-average number of diluted common shares	**1 549**	1 582
(dollars per common share)		
Basic earnings per share	**1.80**	2.74
Diluted earnings per share	**1.79**	2.67

(1) Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have a dilutive impact for the years ended December 31, 2012 and 2011.

13. CASH AND CASH EQUIVALENTS

($ millions)	Dec 31 2012	Dec 31 2011
Cash	**636**	832
Cash equivalents	**3 757**	2 971
	4 393	3 803

14. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	2012	2011
Accounts receivable	**186**	(263)
Inventories	**451**	(1 064)
Accounts payable and accrued liabilities	**(1 738)**	1 322
Provisions	**45**	203
Income taxes payable/receivable	**106**	70
	(950)	268
Relating to:		
Operating activities	**(899)**	242
Investing activities	**(51)**	26

15. INVENTORIES

($ millions)	Dec 31 2012	Dec 31 2011
Crude oil	**1 091**	1 321
Refined products	**1 569**	1 741
Materials, supplies and merchandise	**597**	592
Energy trading commodity inventories	**486**	551
	3 743	4 205

During 2012, product inventories of $17.7 billion (2011 – $18.7 billion) were expensed. There was a write-down of inventories of $45 million in 2012 (2011 – $33 million).

16. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2010	16 981	42 717	59 698
Additions	1 358	4 952	6 310
Transfers from exploration and evaluation	237	—	237
Acquisitions (note 31)	—	126	126
Changes in decommissioning and restoration	1 862	15	1 877
Disposals	(405)	(2 717)	(3 122)
Foreign exchange adjustments	256	50	306
At December 31, 2011	20 289	45 143	65 432
Additions	**1 739**	**4 955**	**6 694**
Transfers from exploration and evaluation	**1 598**	**—**	**1 598**
Changes in decommissioning and restoration	**899**	**92**	**991**
Disposals	**(49)**	**(185)**	**(234)**
Foreign exchange adjustments	**(22)**	**(55)**	**(77)**
At December 31, 2012	**24 454**	**49 950**	**74 404**
Accumulated provision			
At December 31, 2010	(3 028)	(6 712)	(9 740)
Depreciation and depletion	(1 622)	(1 770)	(3 392)
Impairment (note 9)	(359)	—	(359)
Disposals	316	356	672
Foreign exchange adjustments	(13)	(11)	(24)
At December 31, 2011	(4 706)	(8 137)	(12 843)
Depreciation and depletion	**(1 634)**	**(2 060)**	**(3 694)**
Impairment (note 9)	**(204)**	**(2 484)**	**(2 688)**
Impairment reversal (note 9)	**34**	**143**	**177**
Disposals	**42**	**57**	**99**
Foreign exchange adjustments	**(25)**	**28**	**3**
At December 31, 2012	**(6 493)**	**(12 453)**	**(18 946)**
Net property, plant and equipment			
December 31, 2011	15 583	37 006	52 589
December 31, 2012	**17 961**	**37 497**	**55 458**

	Dec 31, 2012			Dec 31, 2011		
($ millions)	**Cost**	**Accumulated provision**	**Net book value**	Cost	Accumulated provision	Net book value
Oil Sands	**47 337**	**(10 440)**	**36 897**	41 679	(6 548)	35 131
Exploration and Production	**16 335**	**(5 691)**	**10 644**	13 757	(4 018)	9 739
Refining and Marketing	**9 498**	**(2 367)**	**7 131**	8 834	(1 953)	6 881
Corporate, Energy Trading and Eliminations	**1 234**	**(448)**	**786**	1 162	(324)	838
	74 404	**(18 946)**	**55 458**	65 432	(12 843)	52 589

At December 31, 2012, the balance of assets under construction, and not subject to depreciation or depletion, was $12.2 billion (December 31, 2011 – $16.2 billion).

At December 31, 2012, Property, Plant and Equipment included finance leases with a net book value of $831 million (December 31, 2011 – $425 million).

17. EXPLORATION AND EVALUATION ASSETS

($ millions)	2012	2011
Beginning of year	**4 554**	3 961
Acquisitions	**—**	716
Additions	**478**	657
Transfers to oil and gas assets	**(1 598)**	(237)
Dry hole expenses	**(145)**	(21)
Disposals	**—**	(263)
Impairment (note 9)	**(88)**	(211)
Amortization	**(24)**	(44)
Foreign exchange adjustments	**107**	(4)
End of year	**3 284**	4 554

18. OTHER ASSETS

($ millions)	Dec 31 2012	Dec 31 2011
Investments	**247**	228
Other	**73**	83
	320	311

19. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
At December 31, 2010	3 019	182	166	55	3 422
Derecognition of goodwill (note 31)	(267)	(8)	—	—	(275)
Additions	—	—	—	3	3
Amortization	—	—	—	(11)	(11)
At December 31, 2011	2 752	174	166	47	3 139
Derecognition of goodwill	**—**	**(2)**	**—**	**—**	**(2)**
Additions	**—**	**—**	**—**	**5**	**5**
Amortization	**—**	**—**	**—**	**(14)**	**(14)**
At December 31, 2012	**2 752**	**172**	**166**	**38**	**3 128**

The company performed its most recent goodwill impairment test at July 31, 2012. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs to sell calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plan have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset.

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserves volumes, operating costs, maintenance and capital expenditures are consistent with the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test.

Future cash flow estimates are adjusted to reflect risks specific to the asset and discounted using after-tax discount rates. The discount rate is calculated based on the weighted-average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 10% at July 31, 2012 (July 31, 2011 – 11%) with a growth rate equal to the current inflation rate of 2% (July 31, 2011 – 2%). As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

The company also performed a goodwill impairment test at July 31, 2012 of its Refining and Marketing operating segment, and no impairment was identified within the operating segment and the associated allocated goodwill.

20. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**Dec 31 2012**	Dec 31 2011
Commercial paper [1]	**775**	761
Other	**1**	2
Total short-term debt	**776**	763

(1) The commercial paper is supported by a revolving credit facility with a separate lender. The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. The weighted-average interest rate as at December 31, 2012 was 0.4% (December 31, 2011 – 0.4%)

Long-Term Debt

($ millions)	**Dec 31 2012**	Dec 31 2011
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, due 2039 (US$750)	**746**	763
6.80% Notes, due 2038 (US$900)	**921**	942
6.50% Notes, due 2038 (US$1150)	**1 144**	1 170
5.95% Notes, due 2035 (US$600)	**556**	566
5.95% Notes, due 2034 (US$500)	**498**	509
5.35% Notes, due 2033 (US$300)	**259**	263
7.15% Notes, due 2032 (US$500)	**498**	509
6.10% Notes, due 2018 (US$1250)	**1 244**	1 271
6.05% Notes, due 2018 (US$600)	**606**	621
5.00% Notes, due 2014 (US$400)	**402**	413
4.00% Notes, due 2013 (US$300)	**299**	305
7.00% Debentures, due 2028 (US$250)	**256**	263
7.875% Debentures, due 2026 (US$275)	**303**	312
9.25% Debentures, due 2021 (US$300)	**361**	376
5.39% Series 4 Medium Term Notes, due 2037	**600**	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700
Total unsecured long-term debt	**9 393**	9 583
Secured long-term debt	**13**	13
Finance leases [2]	**894**	476
Deferred financing costs	**(51)**	(56)
	10 249	10 016
Current portion of long-term debt		
Finance leases	**(12)**	(12)
4.00% Notes, due July 2013 (US$300)	**(299)**	—
	(311)	(12)
Total long-term debt	**9 938**	10 004

(2) Interest rates range from 4.6% to 13.4% and maturity dates range from 2017 to 2037.

Scheduled Debt Repayments

Scheduled principle repayments for finance leases, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2013	1 087
2014	427
2015	18
2016	19
2017	19
Thereafter	9 447
	11 017

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	**2012**
Fully revolving for a period of one year after term-out date (November 2013)	**2 000**
Fully revolving and expires in 2013-2014	**924**
Fully revolving for a period of four years and expires in 2016	**3 000**
Can be terminated at any time at the option of the lenders	**379**
Total credit facilities	**6 303**
Credit facilities supporting outstanding commercial paper	**(775)**
Credit facilities supporting standby letters of credit(3)	**(793)**
Total unutilized credit facilities	**4 735**

(3) The company secures certain obligations and commitments with letters of credit, of which $150 million is pledged with cash as at December 31, 2012.

21. OTHER LONG-TERM LIABILITIES

($ millions)	**Dec 31 2012**	Dec 31 2011
Pensions and other post-retirement benefits (note 22)	**1 634**	1 683
Share-based compensation plans (note 25)	**242**	187
Deferred revenue	**77**	84
Fort Hills purchase obligation (1)	**223**	275
Libya EPSAs signature bonus (2)	**72**	73
Other	**62**	90
	2 310	2 392

(1) As part of the 2009 acquisition of Petro-Canada, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project. To pay for this investment, the company will fund $375 million of expenditures in excess of its working interest. At December 31, 2012, the carrying amount of the Fort Hills obligation, based on the discounted estimated payout pattern for the funding, was $300 million (2011 – $327 million), of which the current portion is $77 million (2011 – $52 million) and is recorded in Accounts Payable and Accrued Liabilities.

(2) The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements (EPSAs) in Libya payable in several instalments through 2013. The company also has a US$47 million obligation related to merger consent. At December 31, 2012, the carrying amount of the total Libya obligation was $86 million (2011– $342 million), of which the current portion is $14 million (2011 – $269 million) and is recorded in Accounts Payable and Accrued Liabilities.

22. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The company's defined benefit pension plans provide pension benefits at retirement based on years of service and final average earnings (if applicable). These obligations are met through funded registered retirement plans and through unregistered supplementary pensions that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. The amount and timing of future funding for these supplementary plans is subject to the funding policy as approved by the Board of Directors. The company's contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The most recent valuations were performed as at December 31, 2012. The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation for accounting purposes.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 11.5% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2012**	2011	**2012**	2011
Change in benefit obligation				
Benefit obligation at beginning of year	**3 698**	3 219	**510**	462
Current service costs	**143**	111	**11**	10
Plan participants' contributions	**14**	13	**—**	—
Benefits paid	**(172)**	(161)	**(18)**	(17)
Interest costs	**163**	165	**22**	23
Foreign exchange	**2**	(18)	**—**	—
Settlements	**2**	(6)	**—**	—
Actuarial loss	**287**	375	**20**	32
Benefit obligation at end of year	**4 137**	3 698	**545**	510
Change in plan assets				
Fair value of plan assets at beginning of year	**2 499**	2 335	**—**	—
Employer contributions	**267**	205	**—**	—
Plan participants' contributions	**14**	13	**—**	—
Benefits paid	**(172)**	(161)	**—**	—
Foreign exchange	**2**	3	**—**	—
Settlements	**2**	(7)	**—**	—
Expected return on plan assets	**164**	160	**—**	—
Actuarial gain (loss)	**67**	(49)	**—**	—
Fair value of plan assets at end of year	**2 843**	2 499	**—**	—
Net unfunded obligation	**1 294**	1 199	**545**	510

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 21) in the Consolidated Balance Sheets.

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2012**	2011	**2012**	2011
Analysis of amount charged to earnings:				
Current service costs	**143**	111	**11**	10
Interest costs	**163**	165	**22**	23
Settlement	**—**	1	**—**	—
Expected return on plan assets	**(164)**	(160)	**—**	—
Defined benefit plans expense	**142**	117	**33**	33
Defined contribution plans expense	**53**	43	**—**	—
Total benefit plans expense charged to earnings	**195**	160	**33**	33

History of surplus and deficit and of experience gains and losses were as follows:

($ millions)	Pension Benefits **2012**	2011	2010	Other Post-Retirement Benefits **2012**	2011	2010
Benefit obligation at December 31	**4 137**	3 698	3 219	**545**	510	462
Less: Fair value of plan assets at December 31	**2 843**	2 499	2 335	**—**	—	—
Net unfunded obligation	**1 294**	1 199	884	**545**	510	462
Actuarial (gain) loss on plan assets	**(67)**	49	(82)	**—**	—	—
Change in assumptions underlying the present value of the plan liabilities	**269**	367	240	**33**	35	45
Experience (gains) and losses arising on the plan liabilities	**18**	8	3	**(13)**	(3)	(5)
Actuarial loss recognized in other comprehensive income	**220**	424	161	**20**	32	40
Cumulative amount recognized in other comprehensive income	**805**	585	161	**92**	72	40

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as projection of salaries and service to retirement.

The significant weighted-average actuarial assumptions were as follows:

(%)	Pension Benefits **2012**	2011	Other Post-Retirement Benefits **2012**	2011
Benefit Obligation at December 31				
Discount rate	**3.90**	4.40	**3.90**	4.40
Rate of compensation increase	**3.65**	3.70	**3.75**	3.70
Benefit Plans Expense year ended December 31				
Discount rate	**4.40**	5.10	**4.40**	5.25
Expected return on plan assets	**6.45**	6.70	**N/A**	N/A
Rate of compensation increase	**3.65**	3.70	**3.75**	4.00

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The expected return on plan assets is the expected long-term rate of return on plan assets for the year and is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

In order to measure the expected cost of other post-retirement benefits, a 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 (2011 – 7%). It is assumed this rate will remain constant in 2013 and 2014 and will decrease 0.5% annually to 5% by 2018, and remain at that level thereafter.

Assumed discount rates and health care cost trend rates may have a significant effect on the amounts reported for pensions and other post-retirement benefit obligations. A 1% change of these assumed assumptions would have the following effects:

	Pension Benefits	
($ millions)	Increase	Decrease
Discount rate		
Effect on the aggregate service and interest costs	(16)	16
Effect on the benefit obligations	(460)	559

	Other Post-Retirement Benefits	
($ millions)	Increase	Decrease
Discount rate		
Effect on the aggregate service and interest costs	(1)	1
Effect on the benefit obligations	(66)	83
Health care cost		
Effect on the aggregate service and interest costs	2	(2)
Effect on the benefit obligations	49	(41)

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically, as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, are as follows:

(%)	**2012**	2011
Equities	**58**	55
Fixed income	**42**	45
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares.

The company expects to make cash contributions to its defined benefit pension plans in 2013 of $276 million.

23. PROVISIONS

($ millions)	Decommissioning and Restoration [1]	Royalties [2]	Other	Total
At December 31, 2010	2 633	370	420	3 423
Liabilities incurred	219	237	42	498
Changes in estimates	1 690	4	1	1 695
Liabilities settled	(496)	(256)	(63)	(815)
Accretion	140	—	6	146
Asset divestitures	(390)	—	—	(390)
Foreign exchange	5	—	1	6
At December 31, 2011	3 801	355	407	4 563
Less: current portion	(372)	(355)	(84)	(811)
	3 429	—	323	3 752
At December 31, 2011	3 801	355	407	4 563
Liabilities incurred	**378**	**317**	**408**	**1 103**
Changes in estimates	**783**	**51**	**(14)**	**820**
Liabilities settled	**(433)**	**(356)**	**(73)**	**(862)**
Accretion	**163**	**—**	**6**	**169**
Foreign exchange	**(4)**	**—**	**—**	**(4)**
At December 31, 2012	**4 688**	**367**	**734**	**5 789**
Less: current portion	**(395)**	**(367)**	**(94)**	**(856)**
	4 293	**—**	**640**	**4 933**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2012 was approximately $8.1 billion (December 31, 2011 – $7.3 billion). A weighted-average credit-adjusted risk-free interest rate of 3.75% was used to discount the provision recognized at December 31, 2012 (December 31, 2011 – 4.3%). The credit-adjusted risk-free rate used reflects the expected timeframe of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years.

(2) In 2010, the Minister of Energy for the Province of Alberta provided notice to the company for the quality and transportation adjustments to be used under the Bitumen Valuation Methodology (BVM) Regulations for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015. In the fourth quarter of 2012, the company agreed to remit $328 million, under protest, related to 2011 and 2012. The company continues to pursue final settlement of the quality adjustment.

24. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Normal Course Issuer Bid

In September 2012, the company completed its first Normal Course Issuer Bid and put option program, and also announced a second Normal Course Issuer Bid program to purchase for cancellation up to $1 billion of its common shares between September 20, 2012 and September 19, 2013.

During the twelve months ended December 31, 2012, the company purchased 46.9 million (2011 – 17.1 million) common shares for total consideration of $1,451 million (2011 – $500 million), net of $1.3 million (2011 – $nil) option premiums recognized in share capital. Of the amount recognized, $609 million (2011 – $222 million) was charged to share capital and $842 million (2011 – $278 million) to retained earnings.

The company has also recorded a liability of $48 million for share purchases that may take place during its internal blackout period under an automatic repurchase plan agreement with an independent broker. Of the liability recognized, $19 million was charged to share capital and $29 million to retained earnings.

25. SHARE-BASED COMPENSATION

(a) Stock Option Plans

Stock options that give the holder the right to purchase common shares at the grant date market price subject to fulfilling vesting terms are accounted for as equity-settled plans. Stock options that the holder can settle for cash or common shares are accounted for as cash-settled plans.

Equity-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. Options granted have a seven-year life and vest annually over a three-year period.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, Key Contributor Stock Options, and legacy Petro-Canada Stock Options. For options granted under these plans, they generally have a seven to ten-year life and vest over periods up to four years. As of January 1, 2013 the SunShare 2012 Performance Stock Option plan will be fully vested. All outstanding unvested options at January 1, 2013 will automatically expire.

The weighted-average fair values of the options granted during the period and the weighted-average assumptions used in their determination are as noted below:

	2012	2011
Annual dividend per share	**\$0.50**	\$0.43
Risk-free interest rate	**1.91%**	2.50%
Expected life	**5 years**	5 years
Expected volatility	**50%**	49%
Weighted-average fair value per option	**\$15.01**	\$16.52

The expected life is based on historical experience and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Cash-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options with TSARs

Options were granted under this plan between August 1, 2009 and July 31, 2010. Each option included a tandem stock appreciation right (TSAR). Options granted have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada Stock Options with CPAs

This plan was discontinued on August 1, 2009. Options were granted to executives and key employees, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life and vest over periods of up to four years.

Changes in the total outstanding stock options were as follows:

	2012		2011	
	Number (thousands)	**Weighted-Average Exercise Price (\$)**	Number (thousands)	Weighted-Average Exercise Price (\$)
Outstanding, beginning of year	**59 178**	**35.25**	67 638	32.94
Granted	**5 101**	**34.50**	5 840	41.08
Exercised	**(10 803)**	**17.31**	(9 918)	20.93
Forfeited/expired	**(6 152)**	**42.08**	(4 382)	40.51
Outstanding, end of year	**47 324**	**38.33**	59 178	35.25
Exercisable, end of year	**29 834**	**36.23**	39 482	32.03

Options are exercised regularly throughout the year. Therefore, the weighted-average share price during the year of $31.94 (2011 – $36.18) is representative of the weighted-average share price at the date of exercise.

For the options outstanding at December 31, 2012, the exercise price ranges and weighted-average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)
11.99-19.99	3 592	2
20.00-29.99	3 494	2
30.00-39.99	14 184	4
40.00-49.99	25 015	3
50.00-69.97	1 039	2
Total	47 324	3

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options:

(thousands)	**Dec 31 2012**	Dec 31 2011
	7 020	10 347

(b) Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised, and is accounted for as a cash-settled plan.

(i) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Changes in the number of outstanding SARs were as follows:

	2012		2011	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**8 752**	**29.32**	11 285	28.97
Granted	**101**	**34.51**	197	41.26
Exercised	**(482)**	**20.53**	(2 003)	29.54
Forfeited/expired	**(595)**	**32.86**	(727)	28.10
Outstanding, end of year	**7 776**	**29.65**	8 752	29.32
Exercisable, end of year	**6 568**	**30.80**	5 625	31.49

(c) Share Unit Plans

The company's share unit plans are accounted for as cash-settled plans.

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at the time of vesting. Typically, RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs. Executives may elect to receive one-half, or all, of their annual incentive payment in the form of DSUs.

Changes in the number of outstanding share units were as follows:

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2010	3 747	6 450	2 299
Granted	2 050	4 237	152
Redeemed for cash	(224)	(840)	(749)
Forfeited/expired	(913)	(553)	—
Outstanding, December 31, 2011	4 660	9 294	1 702
Granted	**1 021**	**6 803**	**198**
Redeemed for cash	**(1 168)**	**(2 666)**	**(263)**
Forfeited/expired	**(135)**	**(566)**	**—**
Outstanding, December 31, 2012	**4 378**	**12 865**	**1 637**

Share-Based Compensation Expense (Recovery)

The following table summarizes the share-based compensation expense (recovery) recorded for all plans within Operating, Selling and General expense in the Consolidated Statements of Comprehensive Income.

($ millions)	**2012**	2011
Equity-settled plans	**83**	94
Cash-settled plans	**269**	(95)
Total share-based compensation expense (recovery)	**352**	(1)

Liability Recognized for Share-Based Compensation

The company has recorded a liability of $523 million as at December 31, 2012 (December 31, 2011 – $405 million), of which $281 million was classified as current (December 31, 2011 – $218 million), based on the fair value of awards accounted for as cash-settled. The intrinsic value of the vested awards at December 31, 2012 was $237 million (December 31, 2011 – $161 million).

26. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and certain portions of other assets and other long-term liabilities.

Non-Derivative Financial Instruments

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

The fair value of the company's financial instrument included in other assets was calculated using a discounted cash flow model. The inputs used in the model were based on observable market data, where available.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2012, the carrying value of fixed-term debt accounted for under amortized cost was $9.4 billion (December 31, 2011 – $9.6 billion) and the fair value at December 31, 2012 was $11.8 billion (December 31, 2011 – $11.4 billion). The estimated fair value of long-term debt is based on pricing sourced from market data.

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues.

Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations. The earnings impact for the year ended December 31, 2012 was a gain of $246 million (2011 – gain of $301 million).

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under IFRS, are believed to be economically effective at managing exposure to commodity price and foreign exchange movements and are a component of the company's overall risk management program.

Gains or losses associated with risk management derivatives are reported in the related operating segment as part of Other Income. The earnings impact associated with these contracts for the year ended December 31, 2012 was a gain of $1 million (2011 – loss of $22 million).

Change in Fair Value of Non-Designated Derivative Financial Instruments

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding at January 1, 2011	13	(87)	(74)
Fair value of contracts realized during the period	9	(248)	(239)
Changes in fair value during the period	(22)	301	279
Fair value of contracts outstanding at December 31, 2011	—	(34)	(34)
Fair value of contracts realized during the period	**(2)**	**(255)**	**(257)**
Changes in fair value during the period	**1**	**246**	**247**
Fair value of contracts outstanding at December 31, 2012	**(1)**	**(43)**	**(44)**

(b) Fair Value Hierarchy

To estimate fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as at December 31, 2012 and 2011:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	1	33	3	37
Accounts payable	(18)	(51)	(2)	(71)
Balance at December 31, 2011	(17)	(18)	1	(34)
Accounts receivable	**5**	**47**	**1**	**53**
Accounts payable	**(12)**	**(85)**	**—**	**(97)**
Balance at December 31, 2012	**(7)**	**(38)**	**1**	**(44)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. Trading activities are defined as activities intended to enhance the company's operations and enhance profitability through informed market calls, market diversification, economies of scale, improved transportation access, and leverage of assets, both physical and contractual. Trading activities also include strategic and operational hedging. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2011.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

Suncor's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and refined product prices. The company may reduce its exposure to commodity price risk through a number of strategies. These strategies include committing a portion of expected crude oil production to fixed price contracts, entering into option contracts to limit exposure to changes in crude oil prices and hedging natural gas exposures to manage regional price differentials.

An increase of US$1.00/barrel of crude oil and US$0.10/mcf of natural gas prices as at December 31, 2012 would decrease pre-tax earnings by approximately $9 million and $2 million, respectively.

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2012 would decrease pre-tax earnings by approximately $86 million.

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars or Euros (€). A 1% strengthening in the Cdn$ relative to the US$ and € as at December 31, 2012 would decrease Other Comprehensive Income by approximately $46 million and $26 million, respectively.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to its revolving-term debt of commercial papers.

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts. The objective of entering into these contracts is to reduce the company's cost of borrowing by managing the mix of fixed and floating interest rate debt. The proportion of floating interest rate exposure at December 31, 2012 was 8% of total debt outstanding. The weighted-average interest rate on total debt for the year ended December 31, 2012 was 6.0%.

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $8 million. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2012, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements and maintaining sufficient cash and credit facilities to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2012 were $4.4 billion and $6.3 billion, respectively.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is maintained through counterparty credit limits.

The following table shows the timing of cash outflows related to trade and other payables and debt.

	December 31, 2012	
($ millions)	Trade and other payables [1]	Debt [2]
Within one year	**6 469**	**1 756**
1 to 3 years	**300**	**1 732**
3 to 5 years	**—**	**1 301**
Over 5 years	**—**	**17 648**
	6 769	**22 437**

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Debt includes short-term debt, long-term debt, finance leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company's credit policy is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2012, substantially all of the company's trade receivables were current. As a result of the continued political unrest in Syria, the company wrote off the remainder of its Syrian receivables ($67 million) in the second quarter of 2012. A write-down of $63 million was previously recorded at December 31, 2011.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2012, the company's exposure was $53 million.

27. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a conservative balance sheet, which supports a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is primarily monitored through net debt to cash flow from operations[1] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt agreements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2012 and 2011.

The company's strategy during 2012, which was unchanged from 2011, was to maintain the measure set out in the following schedule. The company believes that achieving this capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets.

At December 31 ($ millions)	Capital Measure Target	**2012**	2011
Components of ratios			
Short-term debt		**776**	763
Current portion of long-term debt		**311**	12
Long-term debt		**9 938**	10 004
Total debt		**11 025**	10 779
Less: Cash and cash equivalents		**4 393**	3 803
Net debt		**6 632**	6 976
Shareholders' equity		**39 223**	38 600
Total capitalization (total debt plus shareholders' equity)		**50 248**	49 379
Cash flow from operations [1]		**9 745**	9 746
Net debt to cash from operations	<2.0 times	**0.7**	0.7
Total debt to total debt plus shareholders' equity		**22%**	22%

(1) Cash flow from operations is expressed before changes in non-cash working capital, and is a non-GAAP financial measure.

28. INTERESTS IN JOINTLY CONTROLLED ENTITIES AND INVESTMENTS IN ASSOCIATES

Significant jointly controlled entities and associates at December 31, 2012 are set out below:

Jointly controlled entities	**%**
Fort Hills Energy L.P.	40.8
Syncrude Canada Ltd. [1]	12.0
Voyageur Upgrader L.P.	51.0
Magrath Windfarm Joint Venture	33.3
Chin Chute Windfarm Joint Venture	33.3
Ripley Windfarm Joint Venture	50.0
Wintering Hills Joint Venture	70.0
Chimies Parachem S.E.C. / Parachem Chemicals L.P.	51.0
UPI Inc.	50.0

Investments in associates	**%**
Montreal Pipeline Ltd.	23.8
Trans-Northern Pipelines Inc.	33.3

(1) Syncrude Canada Ltd. is the operator of the Syncrude oil sands joint venture, a jointly controlled asset. Syncrude Canada Ltd. is responsible for the management and administration of this asset.

Summarized financial information for the company's share of its jointly controlled entities and investments in associates are shown below:

(a) Jointly controlled entities

($ millions)	**Dec 31 2012**	Dec 31 2011
Current assets	**196**	127
Non-current assets	**1 535**	2 935
	1 731	3 062
Current liabilities	**355**	135
Non-current liabilities	**153**	146
	508	281
Revenues and other income	**533**	541
Less: Expenses	**2 432**	746
Net loss	**(1 899)**	(205)

(b) Investments in associates

($ millions)	**Dec 31 2012**	Dec 31 2011
Current assets	**7**	7
Non-current assets	**82**	84
	89	91
Current liabilities	**18**	21
Non-current liabilities	**34**	39
	52	60
Revenues and other income	**42**	38
Less: Expenses	**34**	32
Net earnings	**8**	6

29. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business. These are primarily sales to associated entities in the company's refining and marketing operations. Operating revenues after eliminations for these transactions were $1,313 million for the year ended December 31, 2012 (2011 – $780 million). At December 31, 2012, amounts due from related parties were $205 million (2011 – $60 million).

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2012**	2011
Short-term benefits	**18**	17
Pension and other post-retirement benefits	**4**	3
Share-based compensation	**32**	29
	54	49

30. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Commitments

Future payments under the company's operating leases for pipeline transportation agreements and for various premises, service stations and other property and equipment are as follows:

($ millions)	Within one year	One to five years	More than five years	Total
Operating and other commitments	**1 572**	**3 973**	**8 176**	**13 721**
Exploration work commitments	**67**	**205**	**—**	**272**
At December 31, 2012	**1 639**	**4 178**	**8 176**	**13 993**

Significant operating leases expire at various dates through 2035. For the year ended December 31, 2012, operating lease expense was $1.2 billion (2011 – $1.1 billion).

In addition to the operating lease commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include commodity purchase obligations which are transacted at market prices.

(b) Contingencies

Legal and environmental contingent liabilities

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities recognized in note 23, which are reviewed individually and are reflected in the company's financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

Operational risk

The company also has exposure to some operational risks, which is reduced by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2012, Suncor's insurance program includes coverage of up to US$1.1 billion for oil sands risks, up to US$1.3 billion for offshore risks and up to US$563 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume limits. The company also has primary property insurance for US$300 million that covers all of Suncor's assets. As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million on certain foreign operations.

During the fourth quarter of 2012, the company received $300 million of risk mitigation proceeds related to its Syrian operations. The proceeds are subject to a provisional repayment should the company resume operations and therefore, have been recorded as a non-current provision at December 31, 2012 (see note 9).

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

(c) Guarantees

At December 31, 2012, the company has various indemnification agreements with third parties as described below and provides loan guarantees to certain retail licensees, wholesale marketers, and the company's subsidiaries.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 20) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working interest share of certain joint venture undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint venture. As at December 31, 2012, the probability is remote that these guarantee commitments will impact the company.

31. TRANSACTION WITH TOTAL

During 2011, Suncor entered into a joint venture with Total E&P Canada Ltd. (Total). As a result of this transaction, Suncor acquired a 36.75% interest in Joslyn for consideration of $842 million after closing adjustments. Total acquired a 49% interest in Voyageur, a 19.2% increase in its interest in Fort Hills (reducing Suncor's interest from 60% to 40.8%), and rights to proprietary mining technology, for cash consideration of $2.662 billion after closing adjustments.

Overall, Suncor recognized a loss of $124 million, after final closing adjustments, related to the disposition of its interests in Voyageur and Fort Hills and the technology sale. The loss included the derecognition of $267 million of goodwill associated with the disposed interests in Fort Hills and Voyageur.

32. SUSPENDED EXPLORATORY WELL COSTS

($ millions)	**2012**	2011
Beginning of year	**387**	266
Additions	**4**	122
Transfers to oil and gas assets	**—**	—
Capitalized exploratory well costs charged to expense	**(73)**	(1)
Foreign exchange adjustments	**—**	—
End of year	**318**	387

The following provides an aging of amounts capitalized as suspended exploratory wells at December 31 based on the completion date of the individual well.

($ millions)	**2012**	2011
Suspended exploratory well costs that have been capitalized for a period less than one year	**4**	122
Suspended exploratory well costs that have been capitalized for a period greater than one year	**314**	265
	318	387
Number of suspended exploratory wells that have been capitalized for a period greater than one year	**8**	9

Suspended capitalized costs for exploratory wells completed prior to the end of 2012 are associated with the following projects located in i) Norway (three wells), ii) Libya (four wells) and iii) East Coast Canada (one well). The projects are awaiting the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, additional geological and geophysical data, and development plan approval.

QUARTERLY FINANCIAL SUMMARY

(unaudited)

($ millions except per share amounts)	For the Quarter Ended Mar 31 2012	June 30 2012	Sept 30 2012	Dec 31 2012	Total Year 2012	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011
Revenues and other income	**9 758**	**9 722**	**9 601**	**9 535**	**38 616**	9 075	9 332	10 419	9 966	38 792
Net earnings (loss)										
Oil Sands	**607**	**356**	**535**	**(1 040)**	**458**	605	371	837	790	2 603
Exploration and Production	**332**	**(430)**	**88**	**148**	**138**	(186)	(212)	420	284	306
Refining and Marketing	**474**	**499**	**708**	**448**	**2 129**	627	313	479	307	1 726
Corporate, Energy Trading and Eliminations	**44**	**(92)**	**224**	**(118)**	**58**	(18)	90	(449)	46	(331)
	1 457	**333**	**1 555**	**(562)**	**2 783**	1 028	562	1 287	1 427	4 304
Operating earnings (loss) (A)										
Oil Sands	**607**	**426**	**535**	**447**	**2 015**	694	371	837	835	2 737
Exploration and Production	**332**	**287**	**88**	**143**	**850**	337	260	389	372	1 358
Refining and Marketing	**474**	**514**	**708**	**448**	**2 144**	627	313	479	307	1 726
Corporate, Energy Trading and Eliminations	**(84)**	**31**	**(28)**	**(38)**	**(119)**	(180)	36	84	(87)	(147)
	1 329	**1 258**	**1 303**	**1 000**	**4 890**	1 478	980	1 789	1 427	5 674
Cash flow from (used in) operations (B)										
Oil Sands	**1 118**	**943**	**1 256**	**1 090**	**4 407**	1 137	733	1 285	1 417	4 572
Exploration and Production	**677**	**656**	**365**	**529**	**2 227**	583	682	801	780	2 846
Refining and Marketing	**741**	**708**	**1 060**	**641**	**3 150**	929	500	611	534	2 574
Corporate, Energy Trading and Eliminations	**(110)**	**37**	**59**	**(25)**	**(39)**	(256)	67	24	(81)	(246)
	2 426	**2 344**	**2 740**	**2 235**	**9 745**	2 393	1 982	2 721	2 650	9 746
Per common share										
Net earnings (loss)										
– basic	**0.93**	**0.21**	**1.01**	**(0.37)**	**1.80**	0.65	0.36	0.82	0.91	2.74
– diluted	**0.93**	**0.20**	**1.01**	**(0.37)**	**1.79**	0.65	0.31	0.76	0.91	2.67
Operating earnings – basic	**0.85**	**0.81**	**0.85**	**0.65**	**3.17**	0.94	0.62	1.14	0.91	3.61
Cash flow from operations – basic	**1.55**	**1.51**	**1.78**	**1.46**	**6.31**	1.52	1.26	1.73	1.69	6.20

(A) Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance.

(B) Cash flow from operations is a non-GAAP financial measure that adjusts cash flow provided by operating activities for changes in non-cash working capital.

QUARTERLY OPERATING SUMMARY

(unaudited)

Oil Sands	Mar 31 2012	June 30 2012	Sept 30 2012	Dec 31 2012	Total Year 2012	Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011
	For the Quarter Ended					For the Quarter Ended				
Total Production (mbbls/d)	**341.1**	**337.8**	**378.9**	**378.7**	**359.2**	360.6	277.2	362.5	356.8	339.3
Excluding Syncrude										
Production										
Total (mbbls/d)	**305.7**	**309.2**	**341.3**	**342.8**	**324.8**	322.1	243.4	326.6	326.5	304.7
Firebag (mbbls/d of bitumen)	**83.6**	**95.8**	**113.0**	**123.4**	**104.0**	55.2	56.4	54.8	71.7	59.5
MacKay River (mbbls/d of bitumen)	**31.0**	**32.0**	**17.0**	**27.9**	**27.0**	32.1	29.4	29.0	29.7	30.0
Sales (mbbls/d)										
Light sweet crude oil	**89.5**	**98.9**	**104.4**	**82.3**	**93.8**	101.0	50.5	80.4	109.9	85.5
Diesel	**32.8**	**27.0**	**28.7**	**9.7**	**24.5**	18.5	11.5	30.7	36.1	24.3
Light sour crude oil	**183.0**	**110.9**	**175.9**	**174.4**	**161.1**	183.0	146.8	194.6	158.1	170.6
Bitumen	**27.5**	**56.7**	**36.4**	**57.3**	**44.5**	23.7	34.0	24.0	14.5	24.0
Total sales	**332.8**	**293.5**	**345.4**	**323.7**	**323.9**	326.2	242.8	329.7	318.6	304.4
Average sales price (1) (dollars per barrel)										
Light sweet crude oil	**98.57**	**88.18**	**87.84**	**90.76**	**91.17**	90.47	107.96	95.75	103.51	98.50
Other (diesel, light sour crude oil and bitumen)	**88.14**	**73.79**	**77.73**	**70.79**	**77.83**	79.05	85.98	81.65	94.07	84.93
Total	**90.95**	**78.64**	**80.79**	**75.87**	**81.69**	82.59	90.56	85.09	97.33	88.74
Operating costs** (dollars per barrel)										
Cash costs	**36.25**	**37.60**	**31.85**	**35.20**	**35.15**	33.35	45.90	34.35	37.05	37.10
Natural gas	**1.85**	**1.40**	**1.50**	**2.80**	**1.90**	2.10	2.50	1.40	1.95	1.95
Cash operating costs* (2)	**38.10**	**39.00**	**33.35**	**38.00**	**37.05**	35.45	48.40	35.75	39.00	39.05
Project start-up costs	**0.05**	**0.75**	**0.55**	**0.60**	**0.50**	1.30	2.05	1.95	0.70	1.45
Total cash operating costs (3)	**38.15**	**39.75**	**33.90**	**38.60**	**37.55**	36.75	50.45	37.70	39.70	40.50
Depreciation, depletion, and amortization	**14.15**	**15.05**	**14.55**	**15.75**	**14.90**	8.30	13.10	9.90	11.55	10.55
Total operating costs (4)	**52.30**	**54.80**	**48.45**	**54.35**	**52.45**	45.05	63.55	47.60	51.25	51.05
Operating costs – In situ bitumen production only** (dollars per barrel)										
Cash costs	**18.80**	**17.75**	**14.60**	**11.90**	**15.50**	16.35	18.30	21.25	23.75	20.10
Natural gas	**3.65**	**3.05**	**3.40**	**5.20**	**3.90**	5.40	5.65	5.55	5.15	5.40
Cash operating costs* (5)	**22.45**	**20.80**	**18.00**	**17.10**	**19.40**	21.75	23.95	26.80	28.90	25.50
Project start-up costs	**(1.25)**	**0.20**	**0.70**	**1.00**	**0.25**	4.20	5.20	6.30	0.50	3.90
Total cash operating costs (6)	**21.20**	**21.00**	**18.70**	**18.10**	**19.65**	25.95	29.15	33.10	29.40	29.40
Depreciation, depletion and amortization	**8.55**	**11.70**	**12.45**	**12.40**	**11.40**	5.65	6.30	7.05	9.90	7.35
Total operating costs (7)	**29.75**	**32.70**	**31.15**	**30.50**	**31.05**	31.60	35.45	40.15	39.30	36.75
Syncrude										
Production (mbbls/d)	**35.4**	**28.6**	**37.6**	**35.9**	**34.4**	38.5	33.8	35.9	30.3	34.6
Average sales price (1) (dollars per barrel)	**98.82**	**90.61**	**90.24**	**90.90**	**92.69**	93.33	111.86	98.35	105.33	101.80
Operating costs**/*** (dollars per barrel)										
Cash costs	**32.25**	**52.15**	**33.40**	**37.60**	**38.10**	34.90	37.40	38.20	45.85	38.80
Natural gas	**1.25**	**0.95**	**0.95**	**1.60**	**1.20**	1.85	1.70	1.45	1.65	1.65
Cash operating costs* (2)	**33.50**	**53.10**	**34.35**	**39.20**	**39.30**	36.75	39.10	39.65	47.50	40.45
Project start-up costs	**—**	**—**	**—**	**—**	**—**	—	—	—	—	—
Total cash operating costs (3)	**33.50**	**53.10**	**34.35**	**39.20**	**39.30**	36.75	39.10	39.65	47.50	40.45
Depreciation, depletion and amortization	**14.80**	**17.15**	**13.80**	**16.90**	**15.55**	20.25	14.10	11.75	16.05	15.60
Total operating costs (4)	**48.30**	**70.25**	**48.15**	**56.10**	**54.85**	57.00	53.20	51.40	63.55	56.05

Footnotes and definitions, see page 135.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Exploration and Production	For the Quarter Ended Mar 31 2012	June 30 2012	Sept 30 2012	Dec 31 2012	Total Year 2012	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011
Total Production (mboe/d)	**221.2**	**204.6**	**156.4**	**177.8**	**189.9**	240.7	182.8	183.5	219.7	206.7
North America Onshore										
Production										
Natural gas (mmcf/d)	**323**	**294**	**279**	**264**	**290**	379	370	346	335	357
Natural gas liquids and crude oil (mbbls/d)	**5.8**	**5.1**	**5.5**	**5.9**	**5.6**	5.4	5.3	4.8	5.0	5.1
Total production (mmcfe/d)	**358**	**325**	**312**	**299**	**323**	411	402	375	365	388
Average sales price (1)										
Natural gas (dollars per mcf)	**2.03**	**1.63**	**2.15**	**2.96**	**2.17**	3.72	3.75	3.52	3.18	3.55
Natural gas liquids and crude oil (dollars per barrel)	**84.34**	**79.25**	**72.91**	**71.43**	**76.93**	77.85	88.90	83.98	90.58	85.30
East Coast Canada										
Production (mbbls/d)										
Terra Nova	**19.6**	**13.3**	**—**	**2.2**	**8.8**	16.9	14.4	19.4	14.3	16.2
Hibernia	**28.7**	**31.0**	**15.7**	**29.1**	**26.1**	29.2	32.1	32.0	30.2	30.9
White Rose	**17.0**	**5.5**	**7.0**	**17.0**	**11.6**	18.9	18.5	17.7	18.9	18.5
	65.3	**49.8**	**22.7**	**48.3**	**46.5**	65.0	65.0	69.1	63.4	65.6
Average sales price (1) (dollars per barrel)	**122.31**	**104.25**	**108.49**	**108.37**	**112.15**	104.01	112.19	111.30	111.77	108.42
International										
Production (mboe/d)										
North Sea										
Buzzard	**57.0**	**57.9**	**41.9**	**35.3**	**48.0**	50.3	32.7	33.1	55.0	42.9
Other North Sea	**—**	**—**	**—**	**—**	**—**	15.4	—	—	—	3.8
Other International										
Libya	**39.2**	**42.7**	**39.8**	**44.4**	**41.5**	24.1	—	—	24.6	12.1
Syria	**—**	**—**	**—**	**—**	**—**	17.4	18.1	18.8	15.9	17.6
	96.2	**100.6**	**81.7**	**79.7**	**89.5**	107.2	50.8	51.9	95.5	76.4
Average sales price (1) (dollars per boe)										
Buzzard	**111.83**	**103.18**	**104.06**	**104.19**	**106.12**	94.12	113.24	111.60	106.41	105.18
Other North Sea	**—**	**—**	**—**	**—**	**—**	92.49	—	—	—	92.49
Other International	**118.47**	**109.44**	**107.32**	**108.05**	**110.65**	91.92	91.42	93.94	102.42	95.76

Footnotes and definitions, see page 135.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Refining and Marketing	For the Quarter Ended Mar 31 2012	June 30 2012	Sept 30 2012	Dec 31 2012	Total Year 2012	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011
Eastern North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**19.2**	**20.2**	**20.2**	**19.6**	**19.8**	21.1	20.9	21.4	20.1	20.9
Distillate	**11.2**	**10.7**	**12.5**	**13.4**	**12.0**	13.4	12.8	12.7	12.2	12.8
Total transportation fuel sales	**30.4**	**30.9**	**32.7**	**33.0**	**31.8**	34.5	33.7	34.1	32.3	33.7
Petrochemicals	**2.2**	**2.3**	**1.7**	**1.8**	**2.0**	2.3	2.2	2.3	1.7	2.1
Asphalt	**1.6**	**2.2**	**3.5**	**2.3**	**2.4**	1.7	2.2	3.5	2.2	2.4
Other	**4.4**	**7.0**	**4.9**	**5.2**	**5.4**	6.1	6.2	4.4	4.6	5.3
Total refined product sales	**38.6**	**42.4**	**42.8**	**42.3**	**41.6**	44.6	44.3	44.3	40.8	43.5
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**30.3**	**30.6**	**32.6**	**32.2**	**31.4**	33.1	31.9	32.3	30.7	32.0
Utilization of refining capacity (%)****	**86**	**87**	**92**	**91**	**89**	97	94	94	90	94
Western North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**19.4**	**20.8**	**21.3**	**20.3**	**20.4**	17.0	18.6	19.7	19.7	18.8
Distillate	**18.4**	**18.8**	**18.2**	**20.5**	**19.0**	17.9	16.2	18.7	17.5	17.6
Total transportation fuel sales	**37.8**	**39.6**	**39.5**	**40.8**	**39.4**	34.9	34.8	38.4	37.2	36.4
Asphalt	**1.2**	**1.8**	**1.9**	**1.5**	**1.6**	0.5	1.2	1.9	1.1	1.2
Other	**2.5**	**3.7**	**3.3**	**2.4**	**3.0**	2.0	1.9	2.1	2.5	2.0
Total refined product sales	**41.5**	**45.1**	**44.7**	**44.7**	**44.0**	37.4	37.9	42.4	40.8	39.6
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**36.4**	**37.3**	**37.6**	**37.3**	**37.2**	35.3	27.0	36.2	32.8	32.8
Utilization of refining capacity (%)****	**98**	**101**	**101**	**101**	**100**	97	75	100	90	91

Footnotes and definitions, see page 135.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Netbacks	For the Quarter Ended Mar 31 2012	June 30 2012	Sept 30 2012	Dec 31 2012	Total Year 2012	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011
North America Onshore (dollars per mcfe)										
Average price realized[8]	**3.98**	**3.48**	**3.81**	**4.65**	**3.97**	4.72	5.15	4.82	4.54	4.81
Royalties	**(0.24)**	**(0.20)**	**(0.28)**	**(0.38)**	**(0.27)**	(0.44)	(0.54)	(0.48)	(0.48)	(0.48)
Transportation costs	**(0.27)**	**(0.34)**	**(0.35)**	**(0.27)**	**(0.31)**	(0.20)	(0.25)	(0.26)	(0.23)	(0.23)
Operating costs	**(1.48)**	**(1.56)**	**(1.63)**	**(1.39)**	**(1.51)**	(1.49)	(1.35)	(1.71)	(1.66)	(1.55)
Operating netback	**1.99**	**1.38**	**1.55**	**2.61**	**1.88**	2.59	3.01	2.37	2.17	2.55
East Coast Canada (dollars per barrel)										
Average price realized[8]	**123.73**	**106.73**	**112.91**	**110.69**	**114.46**	105.84	114.23	112.84	114.35	110.31
Royalties	**(34.72)**	**(38.83)**	**(31.16)**	**(27.17)**	**(33.40)**	(32.04)	(34.99)	(33.56)	(36.95)	(34.49)
Transportation costs	**(1.42)**	**(2.48)**	**(4.42)**	**(2.32)**	**(2.31)**	(1.83)	(2.04)	(1.54)	(2.58)	(1.89)
Operating costs	**(8.53)**	**(12.71)**	**(33.17)**	**(12.00)**	**(13.57)**	(8.14)	(7.26)	(6.69)	(9.36)	(8.04)
Operating netback	**79.06**	**52.71**	**44.16**	**69.20**	**65.18**	63.83	69.94	71.05	65.46	65.89
North Sea – Buzzard (dollars per barrel)										
Average price realized[8]	**114.13**	**105.55**	**106.35**	**106.62**	**108.46**	96.09	115.21	113.65	108.43	107.18
Transportation costs	**(2.30)**	**(2.37)**	**(2.29)**	**(2.43)**	**(2.34)**	(1.97)	(1.97)	(2.05)	(2.02)	(2.00)
Operating costs	**(4.80)**	**(3.36)**	**(8.24)**	**(10.71)**	**(6.38)**	(3.50)	(6.66)	(6.34)	(3.64)	(4.71)
Operating netback	**107.03**	**99.82**	**95.82**	**93.48**	**99.74**	90.62	106.58	105.26	102.77	100.47
Other North Sea (dollars per boe)										
Average price realized[8]	**—**	**—**	**—**	**—**	**—**	94.86	—	—	—	94.86
Transportation costs	**—**	**—**	**—**	**—**	**—**	(2.37)	—	—	—	(2.37)
Operating costs	**—**	**—**	**—**	**—**	**—**	(17.82)	—	—	—	(17.82)
Operating netback	**—**	**—**	**—**	**—**	**—**	74.67	—	—	—	74.67
Other International (dollars per boe)										
Average price realized[8]	**118.84**	**109.79**	**107.67**	**108.34**	**110.99**	92.28	91.67	94.23	102.68	96.06
Royalties	**(67.13)**	**(57.50)**	**(61.02)**	**(81.09)**	**(66.93)**	(64.12)	(41.35)	(46.89)	(54.06)	(54.69)
Transportation costs	**(0.37)**	**(0.35)**	**(0.35)**	**(0.29)**	**(0.34)**	(0.36)	(0.25)	(0.29)	(0.26)	(0.30)
Operating costs	**(1.86)**	**(2.76)**	**(1.13)**	**(1.97)**	**(1.94)**	(5.21)	(8.48)	(6.84)	(7.52)	(6.75)
Operating netback	**49.48**	**49.18**	**45.17**	**24.99**	**41.78**	22.59	41.59	40.21	40.84	34.32

Footnotes and definitions, see page 135.

FIVE-YEAR FINANCIAL SUMMARY[A]

(unaudited)

($ millions)	**2012**	2011	2010	2009	2008
Revenues and other income					
Oil Sands[B]	**10 838**	11 235	9 424	6 539	8 639
Exploration and Production	**4 916**	5 309	5 927	2 305	579
Refining and Marketing	**26 348**	25 771	20 881	11 851	9 258
Corporate, Energy Trading and Eliminations	**(3 486)**	(3 523)	(3 628)	4 785	10 161
	38 616	38 792	32 604	25 480	28 637
Net earnings (loss)					
Oil Sands	**458**	2 603	1 520	557	2 875
Exploration and Production	**138**	306	1 938	78	89
Refining and Marketing	**2 129**	1 726	819	407	(22)
Corporate, Energy Trading and Eliminations	**58**	(331)	(448)	104	(805)
	2 783	4 304	3 829	1 146	2 137
Cash flow from (used in) operations					
Oil Sands	**4 407**	4 572	2 777	1 251	3 507
Exploration and Production	**2 227**	2 846	3 325	1 280	367
Refining and Marketing	**3 150**	2 574	1 538	921	220
Corporate, Energy Trading and Eliminations	**(39)**	(246)	(984)	(653)	(37)
	9 745	9 746	6 656	2 799	4 057
Capital and exploration expenditures					
Oil Sands	**4 957**	5 100	3 709	2 831	7 413
Exploration and Production	**1 261**	874	1 274	986	342
Refining and Marketing	**646**	633	667	380	207
Corporate, Energy Trading and Eliminations	**95**	243	360	70	58
	6 959	6 850	6 010	4 267	8 020
Total assets	**76 449**	74 777	68 607	69 746	32 528
Ending capital employed					
Short-term and long-term debt, less cash and cash equivalents	**6 632**	6 976	11 254	13 377	7 226
Shareholders' equity	**39 223**	38 600	35 192	34 111	14 523
	45 855	45 576	46 446	47 488	21 749
Less capitalized costs related to major projects in progress	**(8 729)**	(12 106)	(12 890)	(10 655)	(5 149)
	37 126	33 470	33 556	36 833	16 600
Total Suncor employees (number at year-end)	**13 932**	13 026	12 076	12 978	6 798

Footnotes, see page 131.

FIVE-YEAR FINANCIAL SUMMARY[A] (continued)

(unaudited)

($ millions)	**2012**	2011	2010	2009	2008
Dollars per common share					
Net earnings	**1.80**	2.74	2.45	0.96	2.29
Cash dividends	**0.50**	0.43	0.40	0.30	0.20
Cash flow from operations	**6.31**	6.20	4.25	2.34	4.36
Ratios					
Return on capital employed (%)[C]	**7.3**	13.8	11.4	2.6	22.5
Return on capital employed (%)[D]	**5.9**	10.1	8.2	1.8	16.3
Debt to debt plus shareholders' equity (%)[E]	**22**	22	26	29	35
Net debt to cash flow from operations (times)[F]	**0.7**	0.7	1.7	4.8	1.8
Interest coverage – cash flow basis (times)[G]	**17.6**	16.4	11.7	7.2	13.0
Interest coverage – net earnings basis (times)[H]	**7.9**	10.7	8.8	3.0	8.9

(A) Annual data for 2008-2009 is presented in accordance with previous Canadian GAAP.

(B) During the first quarter of 2012, the company completed a review of the presentation of purchase and sale transactions in its Oil Sands segment. It was determined that certain transactions previously recorded on a gross basis are more appropriately reflected through net presentation. Annual data for 2011 has been reclassified for comparability with current presentation.

(C) Net earnings adjusted for after-tax interest expense and after-tax foreign exchange loss (gain) on U.S. denominated long-term debt for the twelve-month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less average capitalized costs related to major projects in progress, on a weighted-average basis. For a detailed annual reconciliation of this measure see the Non-GAAP Financial Measures Advisory section of Suncor's 2012 Management Discussion and Analysis.

(D) Average capital employed including capitalized costs related to major projects in progress.

(E) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(F) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

(G) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(H) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

ANNUAL OPERATING SUMMARY

(unaudited)

Oil Sands	2012	2011	2010	2009	2008
Total Production (mbbls/d)	**359.2**	339.3	318.2	306.7	228.0
Excluding Syncrude					
Production					
Total (mbbls/d)	**324.8**	304.7	283.0	290.6	228.0
Firebag (mbbls/d of bitumen)	**104.0**	59.5	53.6	49.1	37.4
MacKay River (mbbls/d of bitumen)	**27.0**	30.0	31.5	12.4	—
Sales (mbbls/d)					
Light sweet crude oil	**93.8**	85.5	82.3	99.6	77.0
Diesel	**24.5**	24.3	20.4	29.1	19.8
Light sour crude oil	**161.1**	170.6	145.2	135.7	128.7
Bitumen	**44.5**	24.0	31.4	11.8	1.5
Total sales	**323.9**	304.4	279.3	276.2	227.0
Average sales price (1) (dollars per barrel)					
Light sweet crude oil*	**91.17**	98.50	79.03	67.26	98.66
Other (diesel, light sour crude oil and bitumen)*	**77.83**	84.93	68.63	64.18	95.14
Total*	**81.69**	88.74	71.69	65.29	96.33
Total	**81.69**	88.74	69.58	61.66	95.96
Operating costs (dollars per barrel)**					
Cash operating costs (2)	**37.05**	39.05	36.70	33.95	38.50
Total cash operating costs (3)	**37.55**	40.50	37.40	34.40	38.90
Total operating costs (4)	**52.45**	51.05	48.55	42.40	45.85
Operating costs – In situ bitumen production only (dollars per barrel)**					
Cash operating costs (5)	**19.40**	25.50	20.25	20.25	25.30
Total cash operating costs (6)	**19.65**	29.40	22.30	21.60	25.95
Total operating costs (7)	**31.05**	36.75	27.75	27.95	32.30
Syncrude					
Production (mbbls/d)	**34.4**	34.6	35.2	16.1	—
Average sales price (1) (dollars per barrel)	**92.69**	101.80	80.93	77.36	—
Operating costs/*** (dollars per barrel)					
Cash operating costs (2)	**39.30**	40.45	36.05	32.50	—
Total cash operating costs (3)	**39.30**	40.45	36.05	32.50	—
Total operating costs (4)	**54.85**	56.05	49.05	44.65	—

Footnotes and definitions, see page 135.

ANNUAL OPERATING SUMMARY (continued)

(unaudited)

Exploration and Production	2012	2011	2010	2009	2008
Total Production (mboe/d)	**189.9**	206.7	296.9	149.3	36.7
North America Onshore					
Production					
Natural gas (mmcf/d)	**290**	357	522	397	202
Natural gas liquids and crude oil (mbbls/d)	**5.6**	5.1	8.8	8.1	3.1
Total production (mmcfe/d)	**323**	388	575	446	220
Average sales price (1)					
Natural gas (dollars per mcf)	**2.17**	3.55	4.04	4.10	8.23
Natural gas* (dollars per mcf)	**2.17**	3.55	4.04	4.08	8.25
Natural gas liquids and crude oil (dollars per barrel)	**76.93**	85.30	67.06	56.84	70.89
East Coast Canada					
Production (mbbls/d)					
Terra Nova	**8.8**	16.2	23.2	8.7	—
Hibernia	**26.1**	30.9	30.9	11.4	—
White Rose	**11.6**	18.5	14.5	4.2	—
	46.5	65.6	68.6	24.3	—
Average sales price (1) (dollars per barrel)	**112.15**	108.42	80.20	76.86	—
International					
Production (mboe/d)					
North Sea					
Buzzard	**48.0**	42.9	55.5	20.0	—
Other North Sea	**—**	3.8	23.5	12.0	—
Other International					
Libya	**41.5**	12.1	35.2	13.7	—
Syria	**—**	17.6	11.6	—	—
Trinidad and Tobago	**—**	—	6.7	4.9	—
	89.5	76.4	132.5	50.6	—
Average sales price (1) (dollars per boe)					
Buzzard	**106.12**	105.18	77.91	69.53	—
Other North Sea	**—**	92.49	78.16	73.52	—
Other International	**110.65**	95.76	70.39	61.25	—

Footnotes and definitions, see page 135.

ANNUAL OPERATING SUMMARY (continued)

(unaudited)

Refining and Marketing	**2012**	2011	2010	2009	2008
Eastern North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**19.8**	20.9	22.2	14.6	7.9
Distillate	**12.0**	12.8	12.4	8.8	5.2
Total transportation fuel sales	**31.8**	33.7	34.6	23.4	13.1
Petrochemicals	**2.0**	2.1	2.5	0.8	0.8
Asphalt	**2.4**	2.4	2.7	1.5	0.6
Other	**5.4**	5.3	5.5	2.0	1.0
Total refined product sales	**41.6**	43.5	45.3	27.7	15.5
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**31.4**	32.0	30.5	29.6*****	11.0
Utilization of refining capacity (%)****	**89**	94	89	87	99
Western North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**20.4**	18.8	18.9	13.0	8.0
Distillate	**19.0**	17.6	18.0	9.5	5.6
Total transportation fuel sales	**39.4**	36.4	36.9	22.5	13.6
Asphalt	**1.6**	1.2	1.3	1.3	1.2
Other	**3.0**	2.0	3.8	3.4	1.2
Total refined product sales	**44.0**	39.6	42.0	27.2	16.0
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**37.2**	32.8	34.6	33.6*****	13.7
Utilization of refining capacity (%)****	**100**	91	95	97	96
Total Retail outlets****	**1 509**	1 732	1 723	1 813	427

Footnotes and definitions, see page 135.

OPERATING SUMMARY INFORMATION

Definitions

(1) Average sales price – This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes and non-production costs). For a reconciliation of this non-GAAP financial measure, see Management's Discussion and Analysis.

(3) Total cash operating costs – Include cash operating costs as defined above and cash start-up costs.

(4) Total operating costs – Include total cash operating costs as defined above and non-cash operating costs.

(5) Cash operating costs – In situ bitumen production – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes and non-production costs). Per barrel amounts are based on in situ production volumes only.

(6) Total cash operating costs – In situ bitumen production – Include cash operating costs – In situ bitumen production as defined above and cash start-up costs. Per barrel amounts are based on in situ production volumes only.

(7) Total operating costs – In situ bitumen production – Include total cash operating costs – In situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in situ production volumes only.

(8) Average price realized – This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** Previously disclosed 2010-2011 quarterly and annual cash operating costs have been restated to reflect revisions to the cash operating costs definition. See the Non-GAAP Financial Measures Advisory section of the Management's Discussion and Analysis. 2008-2009 annual cash operating costs have not been restated.

*** Users are cautioned that the Syncrude cash costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing operations of each company as well as their respective accounting policy choices.

**** As of January 1, 2012, the Montreal and the Commerce City refineries' nameplate capacities increased to 137 mbbls/d and 98 mbbls/d, respectively. Comparative utilization percentages have not been restated.

***** For the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

****** Annual data for 2012 does not include certain joint operated retail stations. Prior year comparatives have not been restated.

Abbreviations

mbbls/d	–	thousands of barrels per day
mcf	–	thousands of cubic feet
mcfe	–	thousands of cubic feet equivalent
mmcf/d	–	millions of cubic feet per day
mmcfe/d	–	millions of cubic feet equivalent per day
boe	–	barrels of oil equivalent
mboe/d	–	thousands of barrels of oil equivalent per day
m^3/d	–	cubic metres per day

Metric conversion

Crude oil, refined products, etc.	$1m^3$ (cubic metre) = approx. 6.29 barrels

SHARE TRADING INFORMATION

(unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2012	**June 30 2012**	**Sept 30 2012**	**Dec 31 2012**	Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011
Share ownership								
Average number outstanding, weighted monthly[a] (thousands)	**1 560 605**	**1 554 172**	**1 536 334**	**1 528 629**	1 570 283	1 573 537	1 572 970	1 566 154
Share price (dollars)								
Toronto Stock Exchange								
High	**37.28**	**33.39**	**34.83**	**34.99**	47.27	44.78	40.70	33.75
Low	**30.07**	**26.97**	**28.43**	**31.23**	36.31	36.31	25.61	23.97
Close	**32.59**	**29.44**	**32.34**	**32.71**	43.48	37.80	26.76	29.38
New York Stock Exchange – US$								
High	**37.37**	**33.77**	**35.82**	**35.18**	48.53	47.00	41.88	33.40
Low	**29.76**	**25.95**	**27.80**	**31.17**	36.54	36.93	24.94	22.55
Close	**32.70**	**28.95**	**32.85**	**32.98**	44.84	39.10	25.44	28.83
Shares traded (thousands)								
Toronto Stock Exchange	**282 262**	**270 745**	**199 120**	**166 385**	314 473	265 385	348 646	333 369
New York Stock Exchange	**317 314**	**327 916**	**247 430**	**232 118**	499 443	402 729	500 005	446 312
Per common share information (dollars)								
Net earnings (loss) attributable to common shareholders	**0.93**	**0.21**	**1.01**	**(0.37)**	0.65	0.36	0.82	0.91
Dividend per common share	**0.11**	**0.13**	**0.13**	**0.13**	0.10	0.11	0.11	0.11

(a) The company had approximately 4 731 holders of record of common shares as at January 31, 2013.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries other than Canada (non-Canadian shareholders) are subject to Canadian withholding tax. The statutory rate of Canadian withholding tax on dividends is 25%, subject to reduction under an applicable tax treaty between Canada and another country. For example, under the tax treaty between Canada and the United States, the withholding tax rate is generally reduced to 15% on dividends paid to residents of the United States that are eligible for the benefit of that tax treaty. The Canada Revenue Agency has released forms, applicable after 2012, for non-Canadian shareholders to evidence entitlement to a reduced withholding tax rate under a tax treaty. The agents responsible for withholding on dividends will generally need to have a duly completed form from a non-Canadian shareholder on file by a particular dividend record date in order for such agents to withhold at an applicable treaty-reduced rate, rather than the full statutory rate of 25%. Non-Canadian shareholders are encouraged to contact their broker (or other applicable agent) regarding the completion and delivery of these forms.

As shareholders are responsible to ensure compliance with Canadian Tax laws and regulations, shareholders are strongly encouraged to seek professional tax and legal counsel with respect to any and all tax matters.

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