



## **Management's discussion and analysis**

for the quarter ended June 30, 2012

Second quarter update.....	4
Financial results .....	9
Our operations and development projects .....	25
Qualified persons .....	30
Additional information.....	30

Throughout this document, the terms we, us, our and Cameco mean Cameco Corporation and its subsidiaries.

## Management's discussion and analysis

This management's discussion and analysis (MD&A) includes information that will help you understand management's perspective of our unaudited condensed consolidated interim financial statements and notes for the quarter ended June 30, 2012 (interim financial statements). The information is based on what we knew as of July 26, 2012 and updates our first quarter and annual MD&A included in our 2011 annual financial review.

As you review the MD&A, we encourage you to read our interim financial statements as well as our audited consolidated financial statements and notes for the year ended December 31, 2011 and annual MD&A of the audited consolidated financial statements. You can find more information about Cameco, including our audited consolidated financial statements and our most recent annual information form, on our website at [cameco.com](http://cameco.com), on SEDAR at [sedar.com](http://sedar.com) or on EDGAR at [sec.gov](http://sec.gov). You should also read our annual information form before making an investment decision about our securities.

The financial information in this MD&A and in our financial statements and notes are prepared according to International Financial Reporting Standards (IFRS), unless otherwise indicated.

Unless we have specified otherwise, all dollar amounts are in Canadian dollars.

### Caution about forward-looking information

Our MD&A includes statements and information about our expectations for the future. When we discuss our strategy, plans and future financial and operating performance, or other things that have not yet taken place, we are making statements considered to be *forward-looking information* or *forward-looking statements* under Canadian and United States securities laws. We refer to them in this MD&A as *forward-looking information*.

Key things to understand about the forward-looking information in this MD&A:

- It typically includes words and phrases about the future, such as: anticipate, estimate, expect, plan, intend, predict, goal, target, project, potential, strategy and outlook (see examples on page 2).
- It represents our current views, and can change significantly.
- It is based on a number of *material assumptions*, including those we have listed on page 3, which may prove to be incorrect.
- Actual results and events may be significantly different from what we currently expect, due to the risks associated with our business. We list a number of these *material risks* on pages 2 and 3. We recommend you also review our annual information form and our annual and first quarter MD&A, which include a discussion of other *material risks* that could cause actual results to differ significantly from our current expectations.
- Forward-looking information is designed to help you understand management's current views of our near and longer term prospects, and it may not be appropriate for other purposes. We will not necessarily update this information unless we are required to by securities laws.

### Examples of forward-looking information in this MD&A

- our strategy for increasing annual production to 40 million pounds by 2018
- our forecasts relating to termination of uranium sales contracts with our customers
- our expectation regarding the closing date for the NUKEM acquisition and that NUKEM will not make any further payments on its debt prior to closing
- our expectations about 2012 and future global uranium supply, consumption, demand and number of new reactors, including the discussion under the heading *Uranium market update*
- our expectation that our average realized uranium price will improve in the fourth quarter of 2012
- the outlook for each of our operating segments for 2012, and our consolidated outlook for the year
- our expectation that we will invest significantly in expanding production at our existing mines and advancing projects as we pursue our growth strategy
- our expectation that existing cash balances and operating cash flows will meet anticipated capital requirements without the need for any significant additional financing
- our expectation that cash balances will decline as we use the funds in our business and pursue our growth plans
- our expectations regarding 2012 quarterly delivery patterns for our uranium and fuel service products
- our expectation that our operating and investment activities in 2012 will not be constrained by the financial covenants in our unsecured revolving credit facility
- our uranium price sensitivity analysis
- forecast production at our uranium operations from 2012 to 2016
- our future plans for each of our uranium operating properties, development projects and projects under evaluation, and fuel services operating sites
- our expectations regarding Cigar Lake

### Material risks

- actual sales volumes or market prices for any of our products or services are lower than we expect for any reason, including changes in market prices or loss of market share to a competitor
- we are adversely affected by changes in foreign currency exchange rates, interest rates or tax rates
- our production costs are higher than planned, or necessary supplies are not available, or not available on commercially reasonable terms
- our estimates of production, purchases, costs, decommissioning or reclamation expenses, or our tax expense estimates, prove to be inaccurate
- our forecasts relating to termination of uranium sales contracts with our customers prove to be inaccurate
- we are unable to enforce our legal rights under our existing agreements, permits or licences, or are subject to litigation or arbitration that has an adverse outcome
- there are defects in, or challenges to, title to our properties
- our mineral reserve and resource estimates are not reliable, or we face unexpected or challenging geological, hydrological or mining conditions
- we are affected by environmental, safety and regulatory risks, including increased regulatory burdens or delays
- we cannot obtain or maintain necessary permits or approvals from government authorities
- we are affected by political risks in a developing country where we operate
- we are affected by terrorism, sabotage, blockades, civil unrest, accident or a deterioration in political support for, or demand for, nuclear energy
- we are impacted by changes in the regulation or public perception of the safety of nuclear power plants, which adversely affect the construction of new plants, the relicensing of existing plants and the demand for uranium
- there are changes to government regulations or policies that adversely affect us, including tax and trade laws and policies
- our uranium and conversion suppliers fail to fulfil delivery commitments
- our Cigar Lake development, mining or production plans are delayed or do not succeed, including as a result of any difficulties encountered with the jet boring mining method or our inability to acquire any of the required jet boring equipment
- we are affected by natural phenomena, including inclement weather, fire, flood and earthquakes
- our operations are disrupted due to problems with our own or our customers' facilities, the unavailability of reagents, equipment, operating parts and supplies critical to production, equipment failure, lack of tailings capacity, labour shortages, labour relations issues, strikes or lockouts, underground floods, cave ins, ground movements, tailings dam failures, transportation disruptions or accidents, or other development and operating risks

- with respect to our NUKEM related forecasts, the risk that the required regulatory approvals may not be obtained in a timely manner or at all or that other closing conditions may not be satisfied and the risk that the amount of NUKEM's debt may change from current levels.

#### **Material assumptions**

- our expectations regarding sales and purchase volumes and prices for uranium, fuel services and electricity
- our expectations regarding the demand for uranium, the construction of new nuclear power plants and the relicensing of existing nuclear power plants not being adversely affected by changes in regulation or in the public perception of the safety of nuclear power plants
- our expected production level and production costs
- our expectations regarding spot prices and realized prices for uranium, and other factors discussed on page 20, *Price sensitivity analysis: uranium*
- our expectations regarding uranium sales contract terminations, tax rates, foreign currency exchange rates and interest rates
- our decommissioning and reclamation expenses
- our mineral reserve and resource estimates, and the assumptions upon which they are based, are reliable
- the geological, hydrological and other conditions at our mines
- our Cigar Lake development, mining and production plans succeed, including the success of the jet boring mining method at Cigar Lake and that we will be able to obtain the additional jet boring system units we require on schedule
- our ability to continue to supply our products and services in the expected quantities and at the expected times
- our ability to comply with current and future environmental, safety and other regulatory requirements, and to obtain and maintain required regulatory approvals
- our operations are not significantly disrupted as a result of political instability, nationalization, terrorism, sabotage, blockades, civil unrest, breakdown, natural disasters, governmental or political actions, litigation or arbitration proceedings, the unavailability of reagents, equipment, operating parts and supplies critical to production, labour shortages, labour relations issues, strikes or lockouts, underground floods, cave ins, ground movements, tailings dam failure, lack of tailings capacity, transportation disruptions or accidents or other development or operating risks
- with respect to our NUKEM related forecasts, we have assumed the regulatory approvals and other closing conditions will be satisfied within the expected timeframes and NUKEM's debt will remain at current levels

## Our strategy

Our corporate growth strategy to double annual uranium production to 40 million pounds by 2018 is as relevant today as it was in 2008 when we set our course. We remain confident in the long-term fundamentals of the nuclear industry. World demand for safe, clean, reliable and affordable energy continues to grow and the need for nuclear energy as part of the world's energy mix remains compelling.

We are preparing our assets now to ensure we can be among the first to respond when the market signals new production is needed and to maintain our position as one of the world's largest uranium producers. In addition, our strategy is to invest in opportunities across the nuclear fuel cycle that we expect will complement and enhance our business.

The projects we have identified to reach our 2018 production target are at various stages of evaluation and the mix may change depending on the results of our evaluations. Our production decisions will be driven by project economics.

Our extraordinary assets, extensive portfolio of long-term sales contracts, employee expertise and comprehensive industry knowledge provide us with the confidence and financial stability to pursue our corporate growth strategy.

You can read more about our strategy in our 2011 annual MD&A.

## Second quarter update

### Our performance

Highlights (\$ millions except where indicated)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
Revenue	391	426	(8)%	955	887	8%
Gross profit	103	108	(5)%	281	244	15%
Net earnings	8	55	(85)%	140	146	(4)%
\$ per common share (diluted)	0.02	0.14	(86)%	0.35	0.37	(5)%
Adjusted net earnings (non-IFRS, see pages 10 and 11)	34	71	(52)%	158	155	2%
\$ per common share (adjusted and diluted)	0.09	0.18	(50)%	0.40	0.39	3%
Cash provided by operations (after working capital changes)	(94)	23	(509)%	318	294	8%
Average realized prices						
Uranium						
\$US/lb	42.08	45.65	(8)%	46.26	46.89	(1)%
\$Cdn/lb	42.21	44.48	(5)%	46.70	46.60	-
Fuel services	16.33	17.24	(5)%	17.82	18.49	(4)%
\$Cdn/kgU						
Electricity	55.00	55.00	-	55.00	54.00	2%
\$Cdn/MWh						

### Second quarter

As we disclosed in our first quarter report, our deliveries in the second quarter were low and we recorded a \$30 million (US) expense related to a contract termination, which impacted our results. In the fourth quarter, we expect more than a third of our 2012 deliveries to occur and an improvement in our average realized uranium price due to pricing under the mix of contracts. Our sales and revenue guidance are unchanged for the year.

Net earnings attributable to our shareholders (net earnings) this quarter were \$8 million (\$0.02 per share diluted) compared to \$55 million (\$0.14 per share diluted) in the second quarter of 2011. On an adjusted basis, our earnings

this quarter were \$34 million (\$0.09 per share diluted) compared to \$71 million (\$0.18 per share diluted) (non-IFRS measure, see pages 10 and 11) in the second quarter of 2011, mainly due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- a \$30 million (US) contract termination charge
- higher expenditures for exploration and administration
- partially offset by increased earnings from our electricity business

See *Financial results by segment* on page 18 for more detailed discussion.

### First six months

Net earnings in the first six months of the year were \$140 million (\$0.35 per share diluted) compared to \$146 million (\$0.37 per share diluted) in the first six months of 2011. Net earnings were lower than in 2011 due to lower mark-to-market gains on foreign exchange derivatives and the items noted below.

On an adjusted basis, our earnings for the first six months of this year were \$158 million (\$0.40 per share diluted) compared to \$155 million (\$0.39 per share diluted) (non-IFRS measure, see pages 10 and 11). The change was due to:

- higher earnings from our electricity business due to an increase in sales, higher realized prices and lower costs
- partially offset by a \$30 million (US) contract termination charge, and higher charges for administration and exploration

See *Financial results by segment* for more detailed discussion.

## Operations update

Highlights		Three months ended June 30			Six months ended June 30		
		2012	2011	change	2012	2011	change
Uranium	Production volume (million lbs)	5.3	5.7	(7)%	10.2	10.5	(3)%
	Sales volume (million lbs)	4.9	5.8	(16)%	13.0	11.9	9%
	Revenue (\$ millions)	206	256	(20)%	607	554	10%
	Gross profit (\$ millions)	42	86	(51)%	184	186	(1)%
Fuel services	Production volume (million kgU)	4.3	4.5	(4)%	8.8	8.8	-
	Sales volume (million kgU)	4.1	4.0	3%	6.9	6.4	8%
	Revenue (\$ millions)	66	70	(6)%	122	119	3%
	Gross profit (\$ millions)	9	13	(31)%	20	19	5%
Electricity	Output (100%) (TWh)	6.5	5.6	16%	12.5	12.0	4%
	Revenue (100%) (\$ millions)	377	314	20%	711	654	9%
	Our share of earnings before taxes (\$ millions)	51	10	410%	78	40	95%

Production in our uranium segment this quarter was down 7% compared to the second quarter of 2011. This is mainly due to lower production from McArthur River/Key Lake where production varies from quarter to quarter depending on the sequencing of mining raises and timing of planned maintenance shutdowns at the mill. For the first six months, production is 3% lower than for the same period in 2011 mainly due to lower production at Smith Ranch-Highland and Inkai. See *Uranium 2012 Q2 updates* starting on page 27 for more information.

Key highlights:

- at McArthur River, we made productivity improvements to our 2013 production plan. See page 27 for more information.

- at Cigar Lake, we are preparing to test the jet boring system underground at site. See page 28 for more information.
- at Millennium, our agreement to purchase AREVA's share of the project for \$150 million closed, increasing our ownership interest to 69.9%. See page 29 for more information.

Production in our fuel services segment was 4% lower this quarter than in the second quarter of 2011, and for the first six months is unchanged compared to last year. We continue to expect production to be between 13 million and 14 million kgU this year.

In our electricity segment, BPLP's generation was 16% higher for the quarter and 4% higher for the first half of the year compared to the same periods last year. The capacity factor this quarter was 91% and 88% for the first six months.

**Also of note this quarter:**

As disclosed in our first quarter MD&A, we terminated a sales contract with one of our customers during the second quarter at a cost of about \$30 million (US), which has been recorded as an expense in our financial statements for the period ended June 30, 2012. The contract included base-escalated pricing terms at rates well below current market prices, and provides for deliveries of 3.4 million pounds covering the years 2012 through 2016, of which 0.8 million pounds is scheduled for 2012. We do not anticipate a significant impact on our financial results for 2012. Some of the material has already been placed into higher-priced contracts and we expect to place the remaining volumes as well. We do not anticipate terminating any other sales arrangements, unless it is expected to be financially beneficial to us.

On May 14, we announced we signed an agreement with Advent International to purchase NUKEM Energy GmbH (NUKEM) for \$136 million (US) on closing, subject to certain adjustments. We will receive the benefits of owning NUKEM and the obligation for the company's net debt of \$164 million (US) as of January 1, 2012. As of June 30, 2012, NUKEM's net debt was \$114 million (US). We do not expect NUKEM to make any further payments on the balance of its debt prior to closing, which we now expect could occur in the third quarter. NUKEM is one of the world's leading traders and brokers of nuclear fuel products and services.

**Uranium market update**

Since the previous quarter, the nuclear industry continues to experience near- to medium-term uncertainty; however, positive developments have emerged as well.

In June, approval was given for the restart of two reactors at the Ohi plant in Japan's Fukui prefecture. The approval was a result of support from the local authorities, and the units being confirmed safe by the Nuclear Safety Commission of Japan and the Nuclear and Industrial Safety Agency. Unit 3 was restarted July 2 and unit 4 on July 18.

The restarts are seen as critical to supplying power to the country through the hot summer months and as Japan works to rebuild its economy and the areas affected by the natural disasters. We also believe these initial restarts will help pave the way for additional restarts in the near future. From a long-term perspective, the government is still in the process of determining what Japan's future energy mix will look like.

In June, Japan also passed a bill to establish a new national, independent nuclear regulatory body – the Nuclear Regulatory Authority (NRA). The new body is important to the future of the country's nuclear program as part of a focus on improving safety, restoring public trust and bringing added certainty to the reactor restart approval process. The NRA is expected to be in place by September.

Overall, the uranium market continues to be in a wait and see mode as utilities are generally well covered for the next few years, and suppliers are similarly heavily committed. However, we have seen the emergence of some long-term contracting over the past few months.

Some clarity has been given around plans for the disposition of uranium from the US Department of Energy (DOE), which made an announcement in May. These changes amount to a potential increase in the disposition of excess

DOE inventory in the near term. Previous DOE Secretarial Determinations have resulted in the disposition of roughly 5 million to 6 million pounds per year, equating to approximately 10% of annual US reactor consumption. The most recent Secretarial Determination outlined programs that could increase excess inventory dispositions to about 15% of annual US reactor consumption. While this announcement effectively introduces additional supply in the near term, we see some benefit in the added certainty around these inventories. To put the potential increase into perspective, it should also be noted that it will not be sufficient to balance the market once the Russian Highly Enriched Uranium (HEU) commercial agreement has expired, and that DOE programs and initiatives have not generally resulted in dispositions equal to volumes provided for under the Secretarial Determinations.

For the long term, a strong and promising growth profile remains for the industry. Ninety-five net new reactors are expected to be built over the next decade, more than 60 of which are currently under construction, driving a looming increase in demand. This translates into an expected annual average growth rate of about 3% for global uranium consumption.

This growth is expected at a time when supply is challenged: a number of new primary supply projects have been put on hold, and a major source of secondary supply – the Russian HEU commercial agreement – is coming to an end after 2013. That alone is the equivalent of removing a mine producing 24 million pounds of uranium per year from the market.

At Cameco, we are well positioned to meet this growing demand and help fill the supply gap by increasing our annual production to 40 million pounds by 2018. We have an extensive base of mineral reserves and resources near existing infrastructure, diversified sources of supply, global exploration program and long-term sales contracts. We are preparing our assets and will continue to look for opportunities to ensure we are among the first to respond to changing market conditions with a continued focus on profitability.

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#### **Caution about forward-looking information relating to our uranium market update**

This discussion of our expectations for the nuclear industry, including its growth profile and future global uranium supply and demand and the number of reactors, is forward-looking information that is based upon the assumptions and subject to the material risks discussed under the heading *Caution about forward-looking information* beginning on page 1.



## Industry prices

	Jun 30 2012	Mar 31 2012	Jun 30 2011	Mar 31 2011
<b>Uranium</b> (\$US/lb U <sub>3</sub> O <sub>8</sub> ) <sup>1</sup>				
Average spot market price	<b>50.75</b>	51.05	52.88	60.50
Average long-term price	<b>61.25</b>	60.00	68.00	70.00
<b>Fuel services</b> (\$US/kgU UF <sub>6</sub> ) <sup>1</sup>				
<b>Average spot market price</b>				
North America	<b>6.63</b>	6.63	11.00	12.00
Europe	<b>7.00</b>	7.00	11.00	12.00
<b>Average long-term price</b>				
North America	<b>16.75</b>	16.75	16.00	15.75
Europe	<b>17.25</b>	17.25	16.25	16.00
Note: the industry does not publish UO <sub>2</sub> prices.				
<b>Electricity</b> (\$/MWh)				
Average Ontario electricity spot price	<b>19.00</b>	20.00	28.00	32.00

<sup>1</sup> Average of prices reported by TradeTech and Ux Consulting (Ux)

On the spot market, where purchases call for delivery within one year, the volume reported for the second quarter of 2012 was just under 8 million pounds. This compares to approximately 10 million pounds in the second quarter of 2011.

The spot market remained stable over the quarter. At the end of the quarter, the average spot price was \$50.75 (US) per pound. On July 23, 2012, Ux reported a spot price of \$50.00 (US) per pound. In general, utilities are well covered under existing contracts, so we expect uranium demand in the near term to remain somewhat discretionary.

The long-term uranium price strengthened during the quarter. Long-term contracts usually call for deliveries to begin more than two years after the contract is finalized, and use a number of pricing formulas, including fixed prices adjusted by inflation indices, and market referenced prices (spot and long-term indicators quoted near the time of delivery).

Spot and long-term UF<sub>6</sub> conversion price indicators held firm throughout the quarter.

### Long-term fundamentals are strong

Electricity is essential to maintaining and improving the standard of living for people throughout the world, and nuclear power continues to be an affordable and sustainable source of safe, clean, reliable energy. The demand for uranium is expected to grow, and along with it, the need for new supply to meet future customer requirements.

Our long history of success comes from many years of hard work and discipline, developing and acquiring the expertise and assets we need to deliver on our strategy. We are well positioned to grow and be successful, and to build value for our shareholders.

#### Shares and stock options outstanding

At July 25, 2012, we had:

- 395,343,018 common shares and one Class B share outstanding
- 9,851,753 stock options outstanding, with exercise prices ranging from \$15.79 to \$54.38

#### Dividend policy

Our board of directors has established a policy of paying a quarterly dividend of \$0.10 (\$0.40 per year) per common share. This policy will be reviewed from time to time based on our cash flow, earnings, financial position, strategy and other relevant factors.

## Financial results

This section of our MD&A discusses our performance, our financial condition and our outlook for the future.

### 2012 Q2 results

Consolidated financial results .....	9
Outlook for 2012 .....	15
Liquidity and capital resources .....	16
Financial results by segment .....	18
Uranium .....	18
Fuel services .....	22
Electricity .....	23

## Consolidated financial results

Highlights (\$ millions except per share amounts)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
Revenue	391	426	(8)%	955	887	8%
Gross profit	103	108	(5)%	281	244	15%
Net earnings	8	55	(85)%	140	146	(4)%
\$ per common share (basic)	0.02	0.14	(86)%	0.35	0.37	(5)%
\$ per common share (diluted)	0.02	0.14	(86)%	0.35	0.37	(5)%
Adjusted net earnings (non-IFRS, see pages 10 and 11)	34	71	(52)%	158	155	2%
\$ per common share (adjusted and diluted)	0.09	0.18	(50)%	0.40	0.39	3%
Cash provided by operations (after working capital changes)	(94)	23	(509)%	318	294	8%

### Net earnings

Net earnings this quarter were \$8 million (\$0.02 per share diluted) compared to \$55 million (\$0.14 per share diluted) in the second quarter of 2011. Lower earnings in 2012 were mainly due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- a \$30 million (US) contract termination charge
- higher expenditures for exploration and administration
- partially offset by higher earnings from our electricity business

Net earnings in the first six months of the year were \$140 million (\$0.35 per share diluted) compared to \$146 million (\$0.37 per share diluted) in the first six months of 2011. Net earnings were lower than in 2011 due to lower mark-to-market gains on foreign exchange derivatives and the items noted below.

On an adjusted basis, our earnings for the first six months of this year were \$158 million (\$0.40 per share diluted) compared to \$155 million (\$0.39 per share diluted) (non-IFRS measure, see pages 10 and 11). The change was due to:

- higher earnings from our electricity business due to an increase in sales, higher realized prices and lower costs
- partially offset by a \$30 million (US) contract termination charge and higher charges for administration and exploration

### Adjusted net earnings (non-IFRS measure)

Adjusted net earnings is a measure that does not have a standardized meaning or a consistent basis of calculation under IFRS (non-IFRS measure). We use this measure as a more meaningful way to compare our financial performance from period to period. We believe that, in addition to conventional measures prepared in accordance with IFRS, certain investors use this information to evaluate our performance. Adjusted net earnings is our net earnings attributable to equity holders, adjusted to better reflect the underlying financial performance for the reporting period. The adjusted earnings measure reflects the matching of the net benefits of our hedging program with the inflows of foreign currencies in the applicable reporting period.

Adjusted net earnings is non-standard supplemental information and should not be considered in isolation or as a substitute for financial information prepared according to accounting standards. Other companies may calculate this measure differently so you may not be able to make a direct comparison to similar measures presented by other companies.

The table below reconciles adjusted net earnings with our net earnings.

(\$ millions)	Three months ended June 30		Six months ended June 30	
	2012	2011	2012	2011
<b>Net earnings</b>	<b>8</b>	55	<b>140</b>	146
<b>Adjustments</b>				
Adjustments on derivatives <sup>1</sup> (pre-tax)	<b>35</b>	22	<b>25</b>	12
Income taxes on adjustments to derivatives	<b>(9)</b>	(6)	<b>(7)</b>	(3)
<b>Adjusted net earnings</b>	<b>34</b>	71	<b>158</b>	155

<sup>1</sup> In 2008, we opted to discontinue hedge accounting for our portfolio of foreign currency forward sales contracts. Since then, we have adjusted our gains or losses on derivatives to reflect what our earnings would have been had hedge accounting been applied.

The table that follows describes what contributed to the changes in adjusted net earnings this quarter.

<b>Change in adjusted net earnings</b> (\$ millions)		<b>Three months ended June 30</b>	<b>Six months ended June 30</b>
<b>Adjusted net earnings – 2011</b>		<b>71</b>	<b>155</b>
<b>Change in gross profit by segment</b> (we calculate gross profit by deducting from revenue the cost of products and services sold, and depreciation and amortization (D&A), net of hedging benefits)			
Uranium	Higher (lower) sales volumes	(13)	17
	Lower realized prices (\$US)	(17)	(8)
	Foreign exchange impact on realized prices	6	9
	Higher costs	(19)	(20)
	Hedging benefits	(15)	(19)
	<b>change - uranium</b>	<b>(58)</b>	<b>(21)</b>
Fuel services	Higher sales volumes	-	1
	Higher (lower) realized prices (\$Cdn)	(4)	(5)
	(Higher) lower costs	1	5
	Hedging benefits	(3)	(2)
	<b>change – fuel services</b>	<b>(6)</b>	<b>(1)</b>
Electricity	Higher sales volumes	2	2
	Higher realized prices (\$Cdn)	4	9
	Lower costs	35	26
	<b>change – electricity</b>	<b>41</b>	<b>37</b>
<b>Other changes</b>			
	Higher exploration expenditures	(3)	(11)
	Higher administration expenditures	(12)	(17)
	Lower income taxes	24	35
	Contract termination charge	(30)	(30)
	Other	7	11
<b>Adjusted net earnings – 2012</b>		<b>34</b>	<b>158</b>

See *Financial results by segment* on page 18 for more detailed discussion.

#### Average realized prices

		<b>Three months ended June 30</b>			<b>Six months ended June 30</b>		
		<b>2012</b>	<b>2011</b>	<b>change</b>	<b>2012</b>	<b>2011</b>	<b>change</b>
Uranium	\$US/lb	<b>42.08</b>	45.65	(8)%	<b>46.26</b>	46.89	(1)%
	\$Cdn/lb	<b>42.21</b>	44.48	(5)%	<b>46.70</b>	46.60	-
Fuel services	\$Cdn/kgU	<b>16.33</b>	17.24	(5)%	<b>17.82</b>	18.49	(4)%
Electricity	\$Cdn/MWh	<b>55.00</b>	55.00	-	<b>55.00</b>	54.00	2%

## Quarterly trends

Highlights (\$ millions except per share amounts)	2012				2011			2010
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue	391	564	970	527	426	461	673	419
Net earnings	8	132	265	39	55	91	206	97
\$ per common share (basic)	0.02	0.33	0.67	0.10	0.14	0.23	0.52	0.25
\$ per common share (diluted)	0.02	0.33	0.67	0.10	0.14	0.23	0.52	0.25
Adjusted net earnings (non-IFRS, see pages 10 and 11)	34	124	249	104	71	84	190	79
\$ per common share (adjusted and diluted)	0.09	0.31	0.63	0.26	0.18	0.21	0.48	0.21
Cash provided by operations (after working capital changes)	(94)	412	258	193	23	271	111	(2)

The table that follows presents the differences between net earnings and adjusted net earnings for the previous seven quarters.

(\$ millions)	2012				2011			2010
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net earnings	8	132	265	39	55	91	206	97
Adjustments								
Adjustments on derivatives <sup>1</sup> (pre-tax)	35	(10)	(22)	88	22	(10)	(22)	(25)
Income taxes on adjustments to derivatives	(9)	2	6	(23)	(6)	3	6	7
Adjusted net earnings (non-IFRS, see pages 10 and 11)	34	124	249	104	71	84	190	79

<sup>1</sup> In 2008, we opted to discontinue hedge accounting for our portfolio of foreign currency forward sales contracts. Since then, we have adjusted our gains or losses on derivatives to reflect what our earnings would have been had hedge accounting been applied.

Key things to note:

- Our financial results are strongly influenced by the performance of our uranium segment, which accounted for 53% of consolidated revenues in the second quarter of 2012.
- The timing of customer requirements, which tend to vary from quarter to quarter, drives revenue in the uranium and fuel services segments.
- Net earnings do not trend directly with revenue due to unusual items and transactions that occur from time to time. We use adjusted net earnings, a non-IFRS measure, as a more meaningful way to compare our results from period to period.
- Cash from operations tends to fluctuate as a result of the timing of deliveries and product purchases in our uranium and fuel services segments.
- Quarterly results are not necessarily a good indication of annual results due to the variability in customer requirements noted above.

## Administration

(\$ millions)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
<b>Direct administration</b>	<b>38</b>	33	15%	<b>73</b>	64	14%
<b>Stock-based compensation</b>	<b>8</b>	1	700%	<b>12</b>	4	200%
<b>Total administration</b>	<b>46</b>	34	35%	<b>85</b>	68	25%

Direct administration costs were \$5 million higher this quarter and \$9 million higher for the first six months than the same periods last year. These increases reflect mainly the following:

- studies and analyses of various opportunities
- enhancements to information systems

Stock-based compensation expenses were \$12 million for the first six months of 2012 compared to \$4 million for the same period in 2011. Our share price appreciated in the first half of 2012 whereas it declined in the first half of 2011.

## Exploration

Uranium exploration expenses were \$18 million this quarter compared to \$15 million in the same quarter in 2011, as exploration activity in Saskatchewan increased. Exploration expenses in the first six months of the year increased to \$41 million from \$30 million in 2011. We expect exploration expenses to be about 15% to 20% higher than they were in 2011 due to an increase in evaluation activities at Kintyre and Inkai block 3. We are also continuing to focus efforts in Canada and the United States.

## Income taxes

In the second quarter of 2012, we recorded an income tax recovery of \$28 million compared to a recovery of \$1 million in the second quarter of 2011. The increase in recoveries this quarter was mainly due to lower pre-tax earnings and a change in the distribution of earnings. In 2012, we recorded losses of \$85 million in Canada compared to \$55 million in 2011, whereas earnings in foreign jurisdictions declined to \$64 million from \$108 million. The tax rate in Canada is higher than the average of the rates in the foreign jurisdictions in which we operate. Also, we received additional certainty on particular tax provisions that allowed us to recognize a \$9 million recovery in our income tax expense. This also applies to our results of the first six months of the year.

On an adjusted basis, we recorded an income tax recovery of \$19 million this quarter compared to an expense of \$5 million in the second quarter of 2011. Our effective tax rate this quarter on an adjusted net earnings basis reflects a recovery of 130% compared to an expense of 6% for the second quarter of 2011.

In the first six months of 2012, we recorded an income tax recovery of \$36 million compared to an expense of \$3 million in 2011. The recovery for the first half of the year was mainly due to lower pre-tax earnings and a change in the distribution of earnings. In 2012, we recorded higher losses in Canada. The tax rate in Canada is higher than the average of the rates in the foreign jurisdictions in which we operate.

On an adjusted basis, we recorded an income tax recovery of \$29 million in the first six months of 2012 compared to an expense of \$6 million in 2011. Our effective tax rate for the first six months of 2012, on an adjusted net earnings basis, reflects a recovery of 23% compared to an expense of 4% in 2011.

(\$ millions)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
<b>Pre-tax Adjusted Earnings<sup>1</sup></b>						
Canada <sup>2</sup>	(49)	(33)	52%	(139)	(63)	121%
Foreign	64	108	(41)%	267	224	19%
Total pre-tax adjusted earnings	15	75	(80)%	128	161	(20)%
<b>Adjusted Income Taxes<sup>2</sup></b>						
Canada <sup>2</sup>	(19)	(8)	(138)%	(38)	(14)	(171)%
Foreign	-	13	(100)%	9	20	(55)%
<b>Adjusted income tax expense (recovery)</b>	<b>(19)</b>	5	(480)%	<b>(29)</b>	6	(583)%
<b>Effective tax rate</b>	<b>(130%)</b>	6%	(2,267)%	<b>(23%)</b>	4%	(675)%

<sup>1</sup> Pre-tax adjusted earnings and adjusted income taxes are non-IFRS measures.

<sup>2</sup> Our IFRS-based measures have been adjusted by the amounts reflected in the table in adjusted net earnings (non-IFRS measure on pages 10 and 11).

### Foreign exchange

At June 30, 2012:

- The value of the US dollar relative to the Canadian dollar was \$1.00 (US) for \$1.02 (Cdn), up from \$1.00 (US) for \$1.00 (Cdn) at March 31, 2012. The exchange rate averaged \$1.00 (US) for \$1.01 (Cdn) over the quarter.
- We had foreign currency contracts of \$1.5 billion (US) and EUR 76 million at June 30, 2012. The US currency contracts had an average exchange rate of \$1.00 (US) for \$1.01 (Cdn).
- The mark-to-market loss on all foreign exchange contracts was \$8 million compared to a \$2 million gain at March 31, 2012. We received cash of \$12 million this quarter related to the settlement of foreign exchange contracts.

## Outlook for 2012

Over the next several years, we expect to invest significantly in expanding production at existing mines and advancing projects as we pursue our growth strategy. The projects are at various stages of development, from exploration and evaluation to construction.

We expect our existing cash balances and operating cash flows will meet our anticipated capital requirements without the need for significant additional funding. Cash balances will decline as we use the funds in our business and pursue our growth plans.

Our outlook for 2012 reflects the growth expenditures necessary to help us achieve our strategy. Our outlook for consolidated tax rate, consolidated capital expenditures, electricity capacity factor and electricity average unit cost of sales (including D&A) has changed. We explain the changes below. All other items in the table are unchanged. We do not provide an outlook for the items in the table that are marked with a dash.

See *Financial results by segment* on page 18 for details.

### 2012 Financial outlook

	Consolidated	Uranium	Fuel services	Electricity
Production	-	21.7 million lbs	13 to 14 million kgU	-
Sales volume	-	31 to 33 million lbs	Decrease 10% to 15%	-
Capacity factor	-	-	-	<b>93%</b>
Revenue compared to 2011	Decrease 0% to 5%	Decrease 0% to 5% <sup>1</sup>	Decrease 10% to 15%	Increase 5% to 10%
Average unit cost of sales (including D&A)	-	Increase 0% to 5% <sup>2</sup>	Increase 10% to 15%	<b>Decrease 15% to 20%</b>
Direct administration costs compared to 2011 <sup>3</sup>	Increase 10% to 15%	-	-	-
Exploration costs compared to 2011	-	Increase 15% to 20%	-	-
Tax rate	<b>Recovery of 5% to 10%</b>	-	-	-
Capital expenditures	<b>\$680 million<sup>4</sup></b>	-	-	\$70 million

<sup>1</sup> Based on a uranium spot price of \$50.00 (US) per pound (the Ux spot price as of July 23, 2012), a long-term price indicator of \$61.50 (US) per pound (the Ux long-term indicator on June 30, 2012) and an exchange rate of \$1.00 (US) for \$1.02 (Cdn).

<sup>2</sup> This increase is based on the unit cost of sale for produced material and committed long-term purchases. If we decide to make discretionary purchases in 2012 then we expect the average unit cost of sales to increase further.

<sup>3</sup> Direct administration costs do not include stock-based compensation expenses. See page 13 for more information.

<sup>4</sup> Does not include our share of capital expenditures at BPLP.

Our customers choose when in the year to receive deliveries of uranium and fuel services products, so our quarterly delivery patterns, and therefore our sales volumes and revenue, can vary significantly. In the fourth quarter, we expect more than a third of our 2012 deliveries to occur and an improvement in our average realized uranium price due to pricing under the mix of contracts. However, not all delivery notices have been received to date, which could alter the delivery patterns.

We now expect a recovery of 5% to 10% for our consolidated tax rate (previously a 0% to 5% recovery). We received additional certainty on particular tax provisions that allowed us to recognize a \$9 million recovery in our income tax expense.

We expect our capital expenditures to be about \$680 million compared to our previous estimate of \$620 million due to changes in scope and scheduling of some of our projects in northern Saskatchewan.



We now expect BPLP's capacity factor for 2012 to be 93% compared to 95% as previously reported. The change in outlook is largely the result of increased outage days in the first half of the year.

BPLP now expects its average unit cost of sales (including D&A) for electricity to decrease by 15% to 20% over 2011 (previously a 5% to 10% decrease). Given the average price of electricity in Ontario for the first half of the year, BPLP expects a decrease in the amount of supplemental rent they will have to pay in 2012. In addition to base rent, BPLP pays an annual supplemental rent (\$32 million for 2012) for each Bruce B operating reactor that increases with inflation. If the annual average price of electricity falls below \$30 per megawatt hour, the supplemental rent decreases to \$12 million per operating reactor.

### **Sensitivity analysis**

For the rest of 2012:

- a change of \$5 (US) per pound in both the Ux spot price (\$50.00 (US) per pound on July 23, 2012) and the Ux long-term price indicator (\$61.50 (US) per pound on June 30, 2012) would change revenue by \$31 million and net earnings by \$16 million
- a change of \$5/MWh in the electricity spot price would change our 2012 net earnings by \$2 million based on the assumption that the spot price will remain below the floor price of \$51.62/MWh provided for under BPLP's agreement with the Ontario Power Authority (OPA)
- a one-cent change in the value of the Canadian dollar versus the US dollar would change revenue by \$4 million and adjusted net earnings by \$1 million. This sensitivity is based on an exchange rate of \$1.00 (US) for \$1.02 (Cdn).

## **Liquidity and capital resources**

### **Cash from operations**

Cash from operations was \$117 million lower this quarter than in 2011 due largely to lower uranium deliveries. Working capital required \$54 million more in 2012 largely as a result of an increase in uranium inventories during the quarter. Not including working capital requirements, our operating cash flows this quarter were lower by \$64 million, based on lower profits in our uranium segment. See *Financial results by segment* on page 18 for details.

Cash from operations was \$24 million higher for the first six months of 2012 than for the same period in 2011 mainly due to higher profits from the electricity business and higher uranium sales volumes. Not including working capital requirements, our operating cash flows in the first six months were down by \$43 million.

### **Debt**

We use debt to provide additional liquidity. We have sufficient borrowing capacity with unsecured lines of credit totalling about \$1.9 billion at June 30, 2012, the same as at March 31, 2012. At June 30, 2012, we had approximately \$679 million outstanding in letters of credit.

### **Debt covenants**

We are bound by certain covenants in our unsecured revolving credit facility. The financially related covenants place restrictions on total debt, including guarantees. As at June 30, 2012, we met these financial covenants and do not expect our operating and investment activities for the remainder of 2012 to be constrained by them.

### **Long-term contractual obligations and off-balance sheet arrangements**

We had two kinds of off-balance sheet arrangements at June 30, 2012:

- purchase commitments
- financial assurances

At the end of the second quarter, we had an agreement to purchase NUKEM for \$136 million (US), and the obligation for its net debt of \$164 million (US) as of January 1, 2012, (\$114 million (US) on June 30, 2012).

Other than the NUKEM agreement, there have been no material changes to our long-term contractual obligations, purchase commitments and financial assurances since December 31, 2011, including payments due for the next five years and thereafter. Our long-term contractual obligations do not include our sales commitments. Please see our annual MD&A for more information.

### Balance sheet

(\$ millions)	Jun 30, 2012	Dec 31, 2011	change
Cash and short-term investments	895	1,202	(26)%
Total debt	992	1,039	(5)%
Inventory	577	494	17%

Total cash and short-term investments at June 30, 2012 were \$895 million, or 26% lower than at December 31, 2011 due to a higher rate of capital expenditures and our purchase of an incremental interest in the Millennium project. Net debt at June 30, 2012 was \$97 million.

Total debt decreased by \$47 million to \$992 million at June 30, 2012. Of this total, \$74 million was classified as current, down \$39 million compared to December 31, 2011. See notes 16 and 17 of our audited annual financial statements for more detail.

Total product inventories increased marginally to \$577 million. Uranium inventories increased, as sales were lower than production and purchases in the first six months of the year. Fuel services inventories increased as sales were also lower than production and purchases.

### Accounting change

In August 2008, we acquired a 70% interest in the Kintyre exploration project in Australia. Previously, we consolidated our investment in Kintyre on the basis that we were able to exercise control over the asset. In the second quarter, we reconsidered the accounting treatment applied to Kintyre and concluded that instead of consolidation of the investment we should recognize only our proportionate interest in the accounts of Kintyre. Accordingly, the non-controlling interest in the assets, liabilities and expenses has been removed from our financial statements. The change in accounting has been applied retrospectively and the comparative statements for 2011 have been recast. There was no impact on retained earnings or net earnings attributable to equity holders for any of the previously reported periods. The most significant changes relate to a reduction of property, plant and equipment of \$183 million and a reduction of the non-controlling interest on the balance sheet of \$182 million. We have concluded that the impact of this change is not material to our financial statements.

## Financial results by segment

### Uranium

Highlights	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
Production volume (million lbs)	5.3	5.7	(7)%	10.2	10.5	(3)%
Sales volume (million lbs)	4.9	5.8	(16)%	13.0	11.9	9%
Average spot price (\$US/lb)	51.33	55.04	(7)%	51.53	61.31	(16)%
Average long-term price (\$US/lb)	61.00	68.33	(11)%	60.67	69.67	(13)%
Average realized price (\$US/lb)	42.08	45.65	(8)%	46.26	46.89	(1)%
Average realized price (\$Cdn/lb)	42.21	44.48	(5)%	46.70	46.60	-
Average unit cost of sales (\$Cdn/lb U <sub>3</sub> O <sub>8</sub> ) (including D&A)	33.49	29.61	13%	32.54	30.95	5%
Revenue (\$ millions)	206	256	(20)%	607	554	10%
Gross profit (\$ millions)	42	86	(51)%	184	186	(1)%
Gross profit (%)	20	34	(41)%	30	34	(12)%

#### Second quarter

Production volumes this quarter were 7% lower compared to the second quarter of 2011 primarily due to lower production from McArthur River/Key Lake. See *Uranium 2012 Q2 updates* starting on page 27 for more information.

Uranium revenues this quarter were down 20% compared to 2011, due to a 16% decrease in sales volumes and a 5% decrease in the \$Cdn realized selling price.

Our realized prices this quarter were lower than the second quarter of 2011 mainly due to lower \$US prices under fixed-price contracts. In the second quarter of 2012, our realized foreign exchange rate was \$1.00, compared to \$0.97 for the prior year.

Total cost of sales (including D&A) decreased by 5% (\$163 million compared to \$171 million in 2011). This was mainly the result of the following:

- a 16% decrease in sales volumes

Partially offset by :

- higher royalty charges (\$24 million in 2012; \$13 million in 2011) due to increased deliveries of Saskatchewan-produced material
- average unit costs for produced uranium being 13% higher due to increased non-cash production costs at our ISR locations and lower total production

The net effect was a \$44 million decrease in gross profit for the quarter.

#### First six months

Production volumes for the first six months of the year were 3% lower than in the previous year due to lower output at Smith Ranch-Highland and Inkai. See *Operating properties* for more information.

For the first six months of 2012, uranium revenues were up 10% compared to 2011, due to a 9% increase in sales volumes. As we anticipated, deliveries in the second quarter were low.

Our \$US realized prices were lower than the first six months of 2011 mainly due to lower prices under market-related contracts being offset by a more favourable exchange rate. In the first six months of 2012, our realized foreign exchange rate was \$1.01 compared to \$0.99 in the prior year.

Total cost of sales (including D&A) increased by 15% (\$423 million compared to \$368 million in 2011). This was mainly the result of the following:

- the 9% increase in sales volumes
- average unit costs for produced uranium were 5% higher due to increased unit production costs relating mainly to the lower production during the first six months. We continue to expect unit costs to increase by 0% to 5% for the year compared to 2011.
- royalty charges in 2012 were \$22 million higher due to increased deliveries of Saskatchewan-produced material
- partially offset by average unit costs for purchased uranium being 22% lower due to decreased purchases at spot prices

The net effect was a \$2 million decrease in gross profit for the first six months.

The following table shows the costs of produced and purchased uranium incurred in the reporting periods (non-IFRS measures see below). These costs do not include selling costs such as royalties, transportation and commissions, nor do they reflect the impact of opening inventories on our reported cost of sales.

(\$Cdn/lb)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
<b>Produced</b>						
Cash cost	<b>20.13</b>	16.95	19%	<b>21.21</b>	19.38	9%
Non-cash cost	<b>7.87</b>	5.89	34%	<b>7.70</b>	6.46	19%
Total production cost	<b>28.00</b>	22.84	23%	<b>28.91</b>	25.84	12%
Quantity produced (million lbs)	<b>5.3</b>	5.7	(7)%	<b>10.2</b>	10.5	(3)%
<b>Purchased</b>						
Cash cost	<b>24.38</b>	26.93	(9)%	<b>28.18</b>	35.90	(22)%
Quantity purchased (million lbs)	<b>2.4</b>	2.8	(14)%	<b>3.8</b>	4.2	(10)%
<b>Totals</b>						
Produced and purchased costs	<b>26.87</b>	24.19	11%	<b>28.71</b>	28.71	-
Quantities produced and purchased (million lbs)	<b>7.7</b>	8.5	(9)%	<b>14.0</b>	14.7	(5)%

Cash cost per pound, non-cash cost per pound and total cost per pound for produced and purchased uranium presented in the above table are non-IFRS measures. These measures do not have a standardized meaning or a consistent basis of calculation under IFRS. We use these measures in our assessment of the performance of our uranium business. We believe that, in addition to conventional measures prepared in accordance with IFRS, certain investors use this information to evaluate our performance and ability to generate cash flow.

These measures are non-standard supplemental information and should not be considered in isolation or as a substitute for measures of performance prepared according to accounting standards. These measures are not necessarily indicative of operating profit or cash flow from operations as determined under IFRS. Other companies may calculate these measures differently so you may not be able to make a direct comparison to similar measures presented by other companies.

To facilitate a better understanding of these measures, the following table presents a reconciliation of these measures to our unit cost of sales for the second quarters and first six months of 2012 and 2011.

#### Cash and total cost per pound reconciliation

(\$ millions)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
<b>Cost of product sold</b>	<b>130.7</b>	148.1	(12)%	<b>358.8</b>	322.8	11%
<b>Add / (subtract)</b>						
Royalties	<b>(24.2)</b>	(13.5)	79%	<b>(57.6)</b>	(36.0)	60%
Standby charges	<b>(5.8)</b>	(5.5)	5%	<b>(12.9)</b>	(10.8)	19%
Other selling costs	<b>(0.4)</b>	(1.6)	(75)%	<b>(2.4)</b>	(6.1)	(61)%
Change in inventories	<b>64.9</b>	44.5	46%	<b>37.5</b>	84.3	(56)%
<b>Cash operating costs (a)</b>	<b>165.2</b>	172.0	(4)%	<b>323.4</b>	354.2	(9)%
<b>Add / (subtract)</b>						
Depreciation and amortization	<b>32.4</b>	22.4	45%	<b>63.8</b>	44.8	42%
Change in inventories	<b>9.3</b>	11.2	(17)%	<b>14.7</b>	23.0	(36)%
<b>Total operating costs (b)</b>	<b>206.9</b>	205.6	1%	<b>401.9</b>	422.0	(5)%
Uranium produced & purchased (millions lbs) (c)	<b>7.7</b>	8.5	(9)%	<b>14.0</b>	14.7	(5)%
<b>Cash costs per pound (a ÷ c)</b>	<b>21.45</b>	20.24	6%	<b>23.10</b>	24.10	(4)%
<b>Total costs per pound (b ÷ c)</b>	<b>26.87</b>	24.19	11%	<b>28.71</b>	28.71	-

#### Price sensitivity analysis: uranium

The table below is *not* a forecast of prices we expect to receive. The prices we actually realize will be different from the prices shown in the table.

It is designed to indicate how our portfolio of long-term contracts would respond to different spot prices. In other words, we would realize these prices only if the contract portfolio remained the same and none of the assumptions we list below change.

We intend to update this table each quarter in our MD&A to reflect deliveries made and changes to our contract portfolio each quarter. As a result we expect the table to change from quarter to quarter.

*Expected realized uranium price sensitivity under various spot price assumptions*  
(rounded to the nearest \$1.00)

(\$US/lb U <sub>3</sub> O <sub>8</sub> )							
Spot prices	\$20	\$40	\$60	\$80	\$100	\$120	\$140
2012	44	45	49	53	57	62	66
2013	43	46	54	63	72	81	88
2014	45	48	56	65	74	83	90
2015	42	46	56	66	77	88	97
2016	44	49	58	68	78	88	97

The table illustrates the mix of long-term contracts in our portfolio, and is consistent with our contracting strategy. The table has been updated to reflect, in the quarter:

- deliveries made and contracts entered into
- changes to deliveries under some contracts where deliveries are tied to reactor requirements

Our portfolio includes a mix of fixed-price and market-related contracts, which we target at a 40:60 ratio. We signed many of our current contracts in 2003 to 2005, when market prices were low (\$11 to \$31 (US)). Those that are fixed at lower prices or have low ceiling prices will yield prices that are lower than current market prices. These older contracts are beginning to expire, and we are starting to deliver into more favourably priced contracts.

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Our portfolio is affected by more than just the spot price. We made the following assumptions (which are not forecasts) to create the table:

*Sales*

- sales volumes on average of 32 million pounds per year

*Deliveries*

- customers take the maximum quantity allowed under each contract (unless they have already provided a delivery notice indicating they will take less)
- we defer a portion of deliveries under existing contracts for 2012

*Prices*

- the average long-term price indicator is the same as the average spot price for the entire year (a simplified approach for this purpose only). Since 1996, the long-term price indicator has averaged 14% higher than the spot price. This differential has varied significantly. Assuming the long-term price is at a premium to spot, the prices in the table will be higher.
- we deliver all volumes that we don't have contracts for at the spot price for each scenario

*Inflation*

- is 2% per year

## Fuel services

(includes results for UF<sub>6</sub>, UO<sub>2</sub> and fuel fabrication)

Highlights	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
Production volume (million kgU)	4.3	4.5	(4)%	8.8	8.8	-
Sales volume (million kgU)	4.1	4.0	3%	6.9	6.4	8%
Realized price (\$Cdn/kgU)	16.33	17.24	(5)%	17.82	18.49	(4)%
Average unit cost of sales (\$Cdn/kgU) (including D&A)	14.07	14.13	-	14.90	15.48	(4)%
Revenue (\$ millions)	66	70	(6)%	122	119	3%
Gross profit (\$ millions)	9	13	(31)%	20	19	5%
Gross profit (%)	14	19	(26)%	16	16	-

### Second quarter

Production volumes in the quarter were 4% lower than in 2011. Production is on track for the year.

Total revenue was \$4 million lower than in 2011 due to a 5% decline in the average realized price for our fuel services products.

Our \$Cdn realized price for fuel services was affected by the mix of products delivered in the quarter. In 2012, a higher proportion of fuel services sales were for UF<sub>6</sub>, which typically yields a lower price than the other fuel services products.

The total cost of sales (including D&A) was \$57 million unchanged compared to the second quarter of 2011.

The net effect was a decrease of \$4 million in gross profit for the quarter.

### First six months

In the first six months of the year, total revenue increased by 3% due to an 8% increase in sales volumes, partially offset by a 4% decline in the realized selling price.

The total cost of products and services sold (including D&A) increased by 2% (\$102 million compared to \$100 million in 2011) due to the decrease in the unit cost of product sold. The average unit cost of sales was 4% lower due to the mix of products delivered in the first six months.

The net effect was a \$1 million increase in gross profit.

## Electricity

### BPLP

(100% – not prorated to reflect our 31.6% interest)

Highlights (\$ millions except where indicated)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
Output - terawatt hours (TWh)	6.5	5.6	16%	12.5	12.0	4%
Capacity factor (the amount of electricity the plants actually produced for sale as a percentage of the amount they were capable of producing)	91%	78%	17%	88%	85%	4%
Realized price (\$/MWh)	55 <sup>1</sup>	55 <sup>2</sup>	-	55 <sup>3</sup>	54 <sup>4</sup>	2%
Average Ontario electricity spot price (\$/MWh)	19	28	(32)%	20	30	(33)%
Revenue	377	314	20%	711	654	9%
Operating costs (net of cost recoveries)	204	270	(24)%	445	503	(12)%
Cash costs	150	224	(33)%	337	410	(18)%
Non-cash costs	54	46	17%	108	93	16%
Income before interest and finance charges	173	44	293%	266	151	76%
Interest and finance charges	10	10	-	10	16	(38)%
Cash from operations	202	121	67%	351	240	46%
Capital expenditures	49	58	(16)%	88	97	(9)%
Distributions	160	55	191%	190	125	52%
Capital calls	17	11	55%	33	11	200%
Operating costs (\$/MWh)	30 <sup>1</sup>	47 <sup>2</sup>	(36)%	34 <sup>3</sup>	41 <sup>4</sup>	(17)%

<sup>1</sup>Three months ended June 30, 2012 are based on actual generation of 6.5 TWh plus deemed generation of 0.3 TWh

<sup>2</sup>Three months ended June 30, 2011 are based on actual generation of 5.6 TWh plus deemed generation of 0.2 TWh

<sup>3</sup>Six months ended June 30, 2012 are based on actual generation of 12.5 TWh plus deemed generation of 0.4 TWh

<sup>4</sup>Six months ended June 30, 2011 are based on actual generation of 12.0 TWh plus deemed generation of 0.2 TWh

### Our earnings from BPLP

Highlights (\$ millions except where indicated)	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
BPLP's earnings before taxes (100%)	163	34	379%	256	135	90%
Cameco's share of pretax earnings before adjustments (31.6%)	52	11	373%	81	43	88%
Proprietary adjustments	(1)	(1)	-	(3)	(3)	-
Earnings before taxes from BPLP	51	10	410%	78	40	95%

### Second quarter

Total electricity revenue increased by 20% this quarter compared to the second quarter of 2011 due to higher output. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$225 million this quarter under its agreement with the OPA, compared to \$123 million in the second quarter of 2011. About 66% of BPLP's output was sold under financial contracts this quarter



compared to 60% in the second quarter of 2011. From time to time BPLP enters the market to lock in the gains under these contracts. Gains on BPLP's contracting activity were slightly higher than in 2011.

The capacity factor was 91% this quarter, up from 78% in the second quarter of 2011 as a result of no planned outage days. This was offset slightly by an increase in the number of unplanned outage days when compared to the second quarter of 2011. Operating costs were lower at \$204 million compared to \$270 million in 2011 mainly due to lower supplemental lease payments and lower maintenance costs.

The result was a \$41 million increase in our share of earnings before taxes.

BPLP distributed \$160 million to the partners in the second quarter, our share was \$51 million. Also, BPLP made capital calls of \$17 million to the partners in the second quarter, our share was \$5 million. The partners have agreed that BPLP will distribute excess cash monthly and will make separate cash calls for major capital projects.

### **First six months**

Total electricity revenue for the first six months increased 9% compared to 2011 due to slightly higher output and higher realized prices. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$409 million in the first six months of 2012 under its agreement with the OPA, compared to \$232 million in the first six months of 2011. The equivalent of about 64% of BPLP's output was sold under financial contracts in the first six months of this year, compared to 48% in 2011. From time to time BPLP enters the market to lock in the gains under these contracts. Gains on BPLP's contracting activity were slightly higher than in 2011.

The capacity factor was 88% for the first six months of this year, up from 85% in the second quarter of 2011 due to a lower volume of outage days during this year's planned outage compared to last year's planned outage. Operating costs were lower at \$445 million compared to \$503 million in 2011 mainly due to lower supplemental lease payments and lower maintenance costs. These decreases were partially offset by higher fuel costs in the first six months of 2012.

The result was a \$38 million increase in our share of earnings before taxes.

BPLP distributed \$190 million to the partners in the first six months of 2012, our share was \$60 million. BPLP made capital calls of \$33 million to the partners in the first six months of this year, our share was \$10 million.

## Our operations and development projects

### Uranium – production overview

Production in our uranium segment this quarter was down 7% compared to the second quarter of 2011 mainly due to lower production from McArthur River/Key Lake. For the first six months, production was down 3% compared to the first half of last year mainly due to lower production at Smith Ranch-Highland and Inkai. See *Uranium 2012 Q2 updates* starting on page 27 for more information.

Key highlight:

- at McArthur River, we made productivity improvements to our 2013 production plan. See page 27 for more information.

### Uranium production

Cameco's share (million lbs U <sub>3</sub> O <sub>8</sub> )	Three months ended June 30			Six months ended June 30		
	2012	2011	change	2012	2011	change
McArthur River/Key Lake	3.3	3.7	(11)%	6.3	6.2	2%
Rabbit Lake	0.9	0.7	29%	1.8	1.7	6%
Smith Ranch-Highland	0.3	0.5	(40)%	0.6	0.9	(33)%
Crow Butte	0.2	0.2	-	0.4	0.4	-
Inkai	0.6	0.6	-	1.1	1.3	(15)%
Total	5.3	5.7	(7)%	10.2	10.5	(3)%

### Outlook

We have geographically diverse sources of production. Our strategy is to increase our annual production to 40 million pounds by 2018, which we expect will come from our operating properties, development projects and projects under evaluation.

*Cameco's share of production — annual forecast to 2016*

Current forecast (million lbs)	2012	2013	2014	2015	2016
McArthur River/Key Lake	13.1	13.1	13.1	13.1	13.1
Rabbit Lake	3.7	3.7	3.7	3.7	3.4
US ISR	2.4	3.0	3.1	3.7	3.8
Inkai <sup>1</sup>	2.5	2.9	2.9	2.9	2.9
Cigar Lake	-	0.3	1.9	5.5	7.9
<b>Total share of production</b>	<b>21.7</b>	<b>23.0</b>	<b>24.7</b>	<b>28.9</b>	<b>31.1</b>
<b>Cameco's share of Inkai's production on which profits are generated<sup>2</sup></b>					
Inkai <sup>1</sup>	2.6	3.0	3.0	3.0	3.0
<b>Total<sup>2</sup></b>	<b>21.8</b>	<b>23.1</b>	<b>24.8</b>	<b>29.0</b>	<b>31.2</b>

<sup>1</sup> We have signed a memorandum of agreement (MOA) with Kazatomprom to increase annual production to 5.2 million pounds (100% basis). Once implemented, we will receive the right to purchase 2.9 million pounds of Inkai's annual production and receive profits on 3.0 million pounds.

<sup>2</sup> We have adjusted the production table to reflect the share of Inkai's production we will use to calculate our profits under the MOA, as described in the note above.

Our 2012 and future annual production targets for Inkai assume, and we expect:

- Inkai will obtain the necessary government permits and approvals to produce at an annual rate of 5.2 million pounds (100% basis), including an amendment to the resource use contract
- we reach a binding agreement with Kazatomprom to finalize the terms of the MOA
- Inkai will ramp up production to an annual rate of 5.2 million pounds (100% basis)

There is no certainty Inkai will receive these permits or approvals or we will reach a binding agreement with Kazatomprom or that Inkai will be able to ramp up production. If Inkai does not, or if the permits and approvals are delayed, Inkai may be unable to achieve its 2012 and future annual production targets and we may have to re-categorize some of Inkai's mineral reserves as resources.

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This forecast is forward-looking information. It is based on the assumptions and subject to the material risks discussed on pages 2 and 3, and specifically on the assumptions and risks listed here. Actual production may be significantly different from this forecast.

*Assumptions*

- we achieve our forecast production for each operation, which requires, among other things, that our mining plans succeed, processing plants and equipment are available and function as designed, we have sufficient tailings capacity and our mineral reserve estimates are reliable
- we obtain or maintain the necessary permits and approvals from government authorities
- our production is not disrupted or reduced as a result of natural phenomena, labour disputes, political risks, blockades or other acts of social or political activism, shortage or lack of supplies critical to production, equipment failures or other development and operation risks

*Material risks that could cause actual results to differ materially*

- we do not achieve forecast production levels for each operation because of a change in our mining plans, processing plants or equipment are not available or do not function as designed, lack of tailings capacity or for other reasons
- we cannot obtain or maintain necessary permits or approvals from government authorities
- natural phenomena, labour disputes, political risks, blockades or other acts of social or political activism, shortage or lack of supplies critical to production, equipment failures or other development and operation risks disrupt or reduce our production

## Uranium 2012 Q2 updates

### Operating properties

#### McArthur River/Key Lake

##### Production update

At McArthur River/Key Lake production was 11% lower in the second quarter compared to the same period last year. Production varies from quarter to quarter depending on the sequencing of mining raises and timing of planned maintenance shutdowns at the mill.

Production for the first six months of the year was 2% higher and is on track for the year.

##### Operations update

At McArthur River, we have mitigated the risk to production in 2013 associated with the transition to the upper mining area of zone 4. We have made productivity improvements on cycle times, which may include the use of blasthole stoping in smaller, lower-grade areas of the mine located away from the freezeways. In addition, we have changed the sequencing of the raises in zone 2, panel 5, which will improve productivity.

We are continuing to commission the new acid plant at Key Lake and address startup issues as they arise.

We are continuing to advance work on the environmental assessment for the Key Lake extension project. We have received comments from the regulators on our draft environmental impact statement and are working to address the questions and issues they have raised.

#### Rabbit Lake

##### Production update

Production remains on track for the year. We expect to see large variations in mill production from quarter to quarter. We manage ore supply to ensure efficient operation of the mill.

##### Operations update

We are continuing our underground reserve replacement drilling. We completed the first phase of our surface exploration drilling program, designed to test and evaluate areas east and northeast of the mine, as well as to the north and south. We are planning further field work in the second half of 2012.

#### Smith Ranch-Highland and Crow Butte

##### Production update

Production for the quarter and the first six months was lower compared to the same periods last year due to lower production from Smith Ranch-Highland. Our ability to bring new wellfields into production at Smith Ranch-Highland continues to be affected by the lengthened review process to obtain regulatory approvals.

##### Operations update

We continue to seek regulatory approvals to proceed with expansions at our various satellite operations in Wyoming and Nebraska. The regulators are constrained by a shortage of resources as they try to work through a large volume of permit and licence amendment requests from resource companies, however we are beginning to receive some approvals. We continue to communicate with them to ensure we understand and meet their information needs in a timely manner.

We have started the initial phases of construction for the satellite plant and the first wellfield at North Butte in Wyoming. Production is expected to start in 2013 and ramp up to a target annual production rate of more than 700,000 pounds per year by 2015.

## **Inkai**

### **Production update**

Production was unchanged for the quarter and 15% lower for the first six months compared to the same periods last year. As our existing wellfields mature, the grades decrease. Average grades at in situ recovery operations typically stabilize at levels lower than initial years as uranium is recovered from a mix of wellfields of varying maturities. We continue to bring on additional wellfields to maintain some new, typically higher grade, wellfields in the production mix. We have increased flow capacity at the Inkai operation and grades were starting to improve at the end of the second quarter.

### **Operations update**

We are pursuing government approval of an amendment to the resource use contract in order to implement the production increase from blocks 1 and 2 to 5.2 million pounds of  $U_3O_8$  (100% basis).

We continue to advance delineation drilling at block 3. In July, Inkai received a construction permit and has begun work on the test leach facility.

In our annual MD&A, we discussed our strategy to implement our 2007 non-binding memorandum of understanding (MOU) with our partner, Kazatomprom, to increase future annual production capacity at Inkai to 10.4 million pounds (100% basis). In addition to the various partner and government approvals required, we also noted that we expected our ability to increase annual uranium production at Inkai would be closely tied to the success of a uranium conversion project. With their success in developing new mines, bringing on new production and signing long-term uranium supply contracts, Kazakhstan and Kazatomprom have stated their interest in furthering their participation in the nuclear fuel cycle by obtaining access to new technologies, their preference being in-country. However, they also recognize the current unfavourable market conditions that exist for  $UF_6$  conversion. As such, we are working with them to identify the best way to meet their longer-term goals.

### **Development project**

## **Cigar Lake**

We continued to make solid progress at Cigar Lake this quarter. The Seru Bay pipeline has progressed to the point where we can use it in the event of a non-routine inflow.

We have lowered the main components of the jet boring system underground at site and have begun assembly. Once we have completed assembly, we will begin testing the system.

In shaft 2, we achieved breakthrough on the 500 metre level. For the remainder of the year we will focus on installing infrastructure, including construction of a concrete ventilation partition, installation of electrical cable, water services, ore slurry pipes and hoist systems.

We will focus on carrying out the remainder of our 2012 plans and implementing the strategies we outlined in our annual MD&A.

We continue to expect first commissioning in ore in mid-2013 and the first packaged pounds in the fourth quarter of 2013.

Cigar Lake is a key part of our plan to increase annual uranium production to 40 million pounds by 2018, and we are committed to bringing this valuable asset safely into production.

## Projects under evaluation

### Millennium

As announced on June 11, 2012, our agreement with AREVA Resources Canada Inc. to purchase AREVA's 27.94% interest in the Millennium project for \$150 million has closed. With the closing, our interest in the Millennium project increases to 69.9%. The remaining 30.1% is owned by JCU (Canada) Exploration Co.

The terms of the purchase agreement provide AREVA with a 4% royalty on revenue from 27.94% of any production that exceeds 63 million pounds U<sub>3</sub>O<sub>8</sub> from the project.

We have submitted the draft environmental impact statement to the regulators. Comments on the draft are expected before the end of the year.

We will continue to advance this project toward a development decision using our stage gate process. See our annual MD&A for more information regarding this project.

### Kintyre

At Kintyre, we have completed the prefeasibility study. Given the measured and indicated mineral resource estimate of about 55 million pounds (100% basis) at an average grade of 0.58%, current uranium prices and continued cost escalation in Western Australia, the economics of the project are challenging. The study was based on an open pit mine with an estimated mine life of about seven years, estimated total production of about 40 million pounds of packaged uranium at an average production rate of about 6 million pounds per year. To break even, the prefeasibility study indicates the project would require an average realized price of about \$67 (US) or about 62 million pounds of packaged production using a uranium price similar to today's spot price.

Despite the challenging economics, we are proceeding to a feasibility study and have accelerated our exploration drilling to determine if we can increase our mineral resource base, which would improve project economics. We continue to have a positive view of the long-term fundamentals of the uranium market and want to ensure our assets are ready to respond when the market signals new production is needed. We expect a feasibility study would take about eighteen months to complete.

Kintyre provides a potential opportunity for us to diversify our portfolio in mining method and geography. A decision to proceed with the feasibility study is not a production decision, but the next step in our stage gate process, which will provide us with more comprehensive information. Our decision to advance to production will ultimately be based on positive project economics.

Future supply of global primary uranium production is uncertain, while global consumption is quite predictable. We believe that to fuel the more than 60 reactors currently under construction and the further growth we expect by 2021, production will have to come from new primary sources of production. In today's environment, those sources of production pose economic challenges, for us and other producers, similar to those we have identified at Kintyre.

## Fuel services 2012 Q2 updates

**Port Hope conversion services**  
 **Cameco Fuel Manufacturing Inc.**  
 **Springfields Fuels Ltd. (SFL)**

### Production update

Fuel services production totalled 4.3 million kgU for the quarter, 4% lower than the same period last year. Production for the first half of the year was 8.8 million kgU, unchanged compared to the same period last year. Production is on track for the year.

## Operations update

On July 6, we announced that unionized employees at our fuel manufacturing operations in Port Hope and Cobourg, Ontario voted to accept a new three-year collective agreement. The agreement includes a 5.25% wage increase over the term of the agreement. The previous agreement expired on June 1, 2012.

## Qualified persons

The technical and scientific information discussed in this MD&A for our material properties (McArthur River/Key Lake, Inkai and Cigar Lake) was approved by the following individuals who are qualified persons for the purposes of NI 43-101:

### *McArthur River/Key Lake*

- David Bronkhorst, vice-president, Saskatchewan mining south, Cameco
- Les Yesnik, general manager, Key Lake, Cameco

### *Cigar Lake*

- Grant Goddard, vice-president, Saskatchewan mining north, Cameco

### *Inkai*

- Dave Neuburger, vice-president, international mining, Cameco

## Additional information

### Related party transactions

We buy significant amounts of goods and services for our Saskatchewan mining operations from northern Saskatchewan suppliers to support economic development in the region. One of these suppliers is Points Athabasca Contracting Ltd. (PACL). In the first half of 2012, we paid PACL \$22 million for construction and contracting services (2011 - \$33 million). These transactions were carried out in the normal course of business. A member of Cameco's board of directors is the president of PACL.

### Critical accounting estimates

In our 2011 annual MD&A, we have identified the critical accounting estimates that reflect the more significant judgments used in the preparation of our financial statements. Please refer to note 2 of our interim financial statements for a detailed description of our application of estimates and judgment in the preparation of our financial information.

### Controls and procedures

As of June 30, 2012, we carried out an evaluation under the supervision and with the participation of our management, including our chief executive officer (CEO) and chief financial officer (CFO), of the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

Based upon that evaluation and as of June 30, 2012, the CEO and CFO concluded that:

- the disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under applicable securities laws is recorded, processed, summarized and reported as and when required
- such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure

There has been no change in our internal control over financial reporting during the quarter ended June 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## **New accounting pronouncements**

### **New standards and interpretations not yet adopted**

We have not yet adopted the standards and amendments to existing standards that have been issued. The standards and amendments, unless otherwise stated, are effective for periods beginning on or after January 1, 2013. We are assessing the impact of the following standards and amendments on our financial statements:

#### **Financial instruments**

In October 2010, the International Accounting Standards Board (“IASB”) issued IFRS 9, *Financial Instruments* (“IFRS 9”). This standard is part of a wider project to replace IAS 39, *Financial Instruments: Recognition and Measurement* (“IAS 39”). IFRS 9 replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The basis of classification depends on the entity’s business model and the contractual cash flow characteristics of the financial asset or liability. The guidance in IAS 39 on impairment of financial assets and hedge accounting continues to apply.

#### **Consolidated financial statements**

In May 2011, the IASB issued IFRS 10, *Consolidated Financial Statements* (“IFRS 10”). This standard establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 defines the principle of control and establishes control as the basis for determining which entities are consolidated in the consolidated financial statements.

#### **Joint arrangements**

In May 2011, the IASB issued IFRS 11, *Joint Arrangements* (“IFRS 11”). This standard establishes principles for financial reporting by parties to a joint arrangement. IFRS 11 requires a party to assess the rights and obligations arising from an arrangement in determining whether an arrangement is either a joint venture or a joint operation. Joint ventures are to be accounted for using the equity method while joint operations will continue to be accounted for using proportionate consolidation.

#### **Disclosure of interests in other entities**

In May 2011, the IASB issued IFRS 12, *Disclosure of Interests in Other Entities* (“IFRS 12”). This standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 integrates and makes consistent the disclosure requirements for a reporting entity’s interest in other entities and presents those requirements in a single standard.

#### **Fair value measurement**

In May 2011, the IASB issued IFRS 13, *Fair Value Measurement* (“IFRS 13”). This standard provides additional guidance where IFRS requires fair value to be used. IFRS 13 defines fair value, sets out in a single standard a framework for measuring fair value and establishes the required disclosures about fair value measurements.



### **Employee benefits**

In June 2011, the IASB issued an amended version of IAS 19, *Employee Benefits* ("IAS 19"). This amendment eliminates the 'corridor method' of accounting for defined benefit plans. Revised IAS 19 also streamlines the presentation of changes in assets and liabilities arising from defined benefit plans, and enhances the disclosure requirements for defined benefit plans.

### **Presentation of other comprehensive income (OCI)**

In June 2011, the IASB issued an amended version of IAS 1, *Presentation of Financial Statements* ("IAS 1"). This amendment is effective for annual periods beginning on or after July 1, 2012 and requires companies preparing financial statements in accordance with IFRS to group together items within OCI that may be reclassified to the profit or loss section of the statement of earnings. Revised IAS 1 also reaffirms existing requirements that items in OCI and profit or loss should be presented as either a single statement or two consecutive statements.

### **Financial assets and financial liabilities**

In December 2011, the IASB issued amendments to IAS 32, *Financial Instruments: Presentation* ("IAS 32") and IFRS 7, *Financial Instruments: disclosures* ("IFRS 7"). The amendments are effective for periods beginning on or after January 1, 2013 for IFRS 7 and January 1, 2014 for IAS 32 and are to be applied retrospectively. These amendments clarify matters regarding offsetting financial assets and financial liabilities as well as related disclosure requirements.

**Cameco Corporation**  
**Consolidated Statements of Earnings**

(Unaudited)

(\$Cdn Thousands, except per share amounts)

(Recast -  
note 3(b))

(Recast -  
note 3(b))

	Note	Three Months Ended		Six Months Ended	
		Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
Revenue from products and services		\$391,424	\$425,705	\$954,682	\$886,806
Cost of products and services sold		226,193	268,059	552,539	543,624
Depreciation and amortization		61,835	49,716	120,830	98,787
<b>Cost of sales</b>		<b>288,028</b>	317,775	<b>673,369</b>	642,411
<b>Gross profit</b>		<b>103,396</b>	107,930	<b>281,313</b>	244,395
Administration		46,408	34,214	85,429	67,981
Exploration		17,888	14,647	40,857	30,486
Research and development		853	732	3,978	1,727
Loss (gain) on sale of assets		913	719	(2,149)	695
<b>Earnings from operations</b>		<b>37,334</b>	57,618	<b>153,198</b>	143,506
Finance costs	8	(12,750)	(19,704)	(35,018)	(39,562)
Gains (losses) on derivatives	13	(22,880)	11,859	1,574	35,588
Finance income		5,808	6,463	11,788	13,116
Share of loss from equity-accounted investees		(1,959)	(2,324)	(2,771)	(5,016)
Other income (expense)		(26,506)	(133)	(25,745)	1,439
<b>Earnings (loss) before income taxes</b>		<b>(20,953)</b>	53,779	<b>103,026</b>	149,071
Income tax expense (recovery)	9	(28,241)	(873)	(35,809)	2,934
<b>Net earnings</b>		<b>\$7,288</b>	<b>\$54,652</b>	<b>\$138,835</b>	<b>\$146,137</b>
<b>Net earnings (loss) attributable to:</b>					
Equity holders		\$7,877	\$54,652	\$139,615	\$146,137
Non-controlling interest		(589)	-	(780)	-
<b>Net earnings</b>		<b>\$7,288</b>	<b>\$54,652</b>	<b>\$138,835</b>	<b>\$146,137</b>
<b>Earnings per common share attributable to equity holders</b>					
Basic	14	\$0.02	\$0.14	\$0.35	\$0.37
Diluted	14	\$0.02	\$0.14	\$0.35	\$0.37

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
 **Consolidated Statements of Comprehensive Income**  
(Unaudited)  
(\$Cdn Thousands)

		(Recast - note 3(b))		(Recast - note 3(b))	
	Note	Three Months Ended		Six Months Ended	
		Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
<b>Net earnings</b>		<b>\$7,288</b>	<b>\$54,652</b>	<b>\$138,835</b>	<b>\$146,137</b>
Other comprehensive income (loss), net of taxes	9				
Exchange differences on translation of foreign operations		15,718	6,997	(3,106)	(14,382)
Gains (losses) on derivatives designated as cash flow hedges		(1,375)	1,511	5,688	3,122
Gains on derivatives designated as cash flow hedges transferred to net earnings		(6,298)	(5,102)	(11,833)	(11,232)
Unrealized gains (losses) on available-for-sale assets		185	217	(90)	684
Losses (gains) on available-for-sale assets transferred to net earnings		8	(5)	(39)	(1,840)
Other comprehensive income (loss), net of taxes		<b>8,238</b>	<b>3,618</b>	<b>(9,380)</b>	<b>(23,648)</b>
<b>Total comprehensive income</b>		<b>\$15,526</b>	<b>\$58,270</b>	<b>\$129,455</b>	<b>\$122,489</b>
<b>Other comprehensive income (loss) attributable to:</b>					
Equity holders		\$8,209	\$3,618	\$(9,290)	\$(23,648)
Non-controlling interest		29	-	(90)	-
<b>Other comprehensive income (loss) for the period</b>		<b>\$8,238</b>	<b>\$3,618</b>	<b>\$(9,380)</b>	<b>\$(23,648)</b>
<b>Total comprehensive income (loss) attributable to:</b>					
Equity holders		\$16,086	\$58,270	\$130,325	\$122,489
Non-controlling interest		(560)	-	(870)	-
<b>Total comprehensive income for the period</b>		<b>\$15,526</b>	<b>\$58,270</b>	<b>\$129,455</b>	<b>\$122,489</b>

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Financial Position**

(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

	Note	As At	
		Jun 30/12	Dec 31/11
<b>Assets</b>			
Current assets			
Cash and cash equivalents		\$313,628	\$398,084
Short-term investments		581,222	804,141
Accounts receivable		320,821	611,815
Current tax assets		33,048	31,388
Inventories	4	577,251	493,875
Supplies and prepaid expenses		198,286	182,037
Current portion of long-term receivables, investments and other	5	75,101	62,433
<b>Total current assets</b>		<b>2,099,357</b>	<b>2,583,773</b>
Property, plant and equipment			
Intangible assets		4,666,684	4,349,492
Long-term receivables, investments and other	5	96,564	98,954
Investments in equity-accounted investees		308,374	283,818
Deferred tax assets		220,822	220,226
Deferred tax assets		134,791	81,392
<b>Total non-current assets</b>		<b>5,427,235</b>	<b>5,033,882</b>
<b>Total assets</b>		<b>\$7,526,592</b>	<b>\$7,617,655</b>
<b>Liabilities and Shareholders' Equity</b>			
Current liabilities			
Accounts payable and accrued liabilities		\$385,104	\$455,499
Current tax liabilities		16,663	39,330
Short-term debt		58,360	97,830
Dividends payable		39,531	39,475
Current portion of finance lease obligation		15,579	14,852
Current portion of other liabilities	6	40,279	50,495
Current portion of provisions		15,936	14,857
<b>Total current liabilities</b>		<b>571,452</b>	<b>712,338</b>
Long-term debt			
Finance lease obligation		795,484	795,144
Other liabilities	6	122,987	130,982
Provisions		523,856	528,264
Deferred tax liabilities		516,948	519,625
Deferred tax liabilities		9,550	8,165
<b>Total non-current liabilities</b>		<b>1,968,825</b>	<b>1,982,180</b>
Shareholders' equity			
Share capital		1,850,598	1,842,289
Contributed surplus		161,518	155,757
Retained earnings		2,935,531	2,874,973
Other components of equity		37,285	46,575
<b>Total shareholders' equity attributable to equity holders</b>		<b>4,984,932</b>	<b>4,919,594</b>
Non-controlling interest			
		1,383	3,543
<b>Total shareholders' equity</b>		<b>4,986,315</b>	<b>4,923,137</b>
<b>Total liabilities and shareholders' equity</b>		<b>\$7,526,592</b>	<b>\$7,617,655</b>

Commitments and contingencies [notes 9,12]

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Changes in Equity**  
(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

	Attributable to equity holders						Total	Non-Controlling Interest	Total Equity
	Share Capital	Contributed Surplus	Retained Earnings	Foreign Currency Translation	Cash Flow Hedges	Available-For-Sale Assets			
Balance at January 1, 2012	\$1,842,289	\$155,757	\$2,874,973	\$26,867	\$19,560	\$148	4,919,594	\$3,543	\$4,923,137
Net earnings	-	-	139,615	-	-	-	139,615	(780)	138,835
Total other comprehensive loss	-	-	-	(3,016)	(6,145)	(129)	(9,290)	(90)	(9,380)
<b>Total comprehensive income for the period</b>	-	-	139,615	(3,016)	(6,145)	(129)	130,325	(870)	129,455
Share-based compensation	-	9,926	-	-	-	-	9,926	-	9,926
Share options exercised	8,309	(4,165)	-	-	-	-	4,144	-	4,144
Dividends	-	-	(79,057)	-	-	-	(79,057)	-	(79,057)
Change in ownership interests in subsidiary	-	-	-	-	-	-	-	(1,290)	(1,290)
<b>Balance at June 30, 2012</b>	<b>\$1,850,598</b>	<b>\$161,518</b>	<b>\$2,935,531</b>	<b>\$23,851</b>	<b>\$13,415</b>	<b>\$19</b>	<b>\$4,984,932</b>	<b>\$1,383</b>	<b>\$4,986,315</b>
Balance at January 1, 2011	1,833,257	142,376	2,690,184	(7,276)	30,306	1,793	4,690,640	-	4,690,640
Net earnings	-	-	146,137	-	-	-	146,137	-	146,137
Total other comprehensive loss	-	-	-	(14,382)	(8,110)	(1,156)	(23,648)	-	(23,648)
<b>Total comprehensive income for the period</b>	-	-	146,137	(14,382)	(8,110)	(1,156)	122,489	-	122,489
Share-based compensation	-	11,320	-	-	-	-	11,320	-	11,320
Share options exercised	8,508	(5,988)	-	-	-	-	2,520	-	2,520
Dividends	-	-	(78,942)	-	-	-	(78,942)	-	(78,942)
Transactions with owners - contributed equity	-	-	-	-	-	-	-	3,376	3,376
<b>Balance at June 30, 2011</b>	<b>\$1,841,765</b>	<b>\$147,708</b>	<b>\$2,757,379</b>	<b>\$(21,658)</b>	<b>\$22,196</b>	<b>\$637</b>	<b>\$4,748,027</b>	<b>\$3,376</b>	<b>\$4,751,403</b>

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Cash Flows**  
(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

(Recast -  
note 3(b))

		<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>Note</b>	<b>Jun 30/12</b>	<b>Jun 30/11</b>	<b>Jun 30/12</b>	<b>Jun 30/11</b>
<b>Operating activities</b>					
Net earnings		\$7,288	\$54,652	\$138,835	\$146,137
Adjustments for:					
Depreciation and amortization		61,835	49,716	120,830	98,787
Deferred charges		(15,568)	(4,460)	(15,640)	(8,186)
Unrealized losses (gains) on derivatives		16,000	15,490	(3,276)	9,856
Share-based compensation	11	7,706	3,225	9,926	11,320
Loss (gain) on sale of assets		913	719	(2,149)	695
Finance costs	8	12,750	19,704	35,018	39,562
Finance income		(5,808)	(6,463)	(11,788)	(13,116)
Share of loss from equity-accounted investees		1,959	2,324	2,771	5,016
Other income		(3,796)	(352)	(3,796)	(4,975)
Income tax expense (recovery)	9	(28,241)	(873)	(35,809)	2,934
Interest received		5,288	5,714	12,230	9,689
Income taxes paid		(6,809)	(9,209)	(53,329)	(47,883)
Income taxes refunded		13,163	-	13,163	-
Other operating items	10	(160,625)	(107,191)	110,687	44,386
<b>Net cash provided by (used in) operations</b>		<b>(93,945)</b>	<b>22,996</b>	<b>317,673</b>	<b>294,222</b>
<b>Investing activities</b>					
Additions to property, plant and equipment		(315,427)	(140,019)	(451,501)	(263,839)
Decrease in short-term investments		328,227	142,719	222,770	10,746
Decrease (increase) in long-term receivables, investments and other		(4,360)	(341)	(29,952)	27,494
Proceeds from sale of property, plant and equipment		3,066	7	3,099	32
<b>Net cash provided by (used in) investing</b>		<b>11,506</b>	<b>2,366</b>	<b>(255,584)</b>	<b>(225,567)</b>
<b>Financing activities</b>					
Decrease in debt		(11,041)	(7,046)	(46,636)	(10,870)
Interest paid		(2,644)	(2,893)	(26,982)	(27,088)
Proceeds from issuance of shares, stock option plan		727	159	6,304	6,938
Dividends paid		(39,525)	(39,470)	(79,000)	(67,075)
<b>Net cash used in financing</b>		<b>(52,483)</b>	<b>(49,250)</b>	<b>(146,314)</b>	<b>(98,095)</b>
Decrease in cash during the period		(134,922)	(23,888)	(84,225)	(29,440)
Exchange rate changes on foreign currency cash balances		503	1,938	(231)	(449)
Cash and cash equivalents at beginning of period		448,047	367,441	398,084	375,380
<b>Cash and cash equivalents at end of period</b>		<b>\$313,628</b>	<b>\$345,491</b>	<b>\$313,628</b>	<b>\$345,491</b>
<b>Cash and cash equivalents is comprised of:</b>					
Cash				\$63,762	\$100,684
Cash equivalents				249,866	244,807
				\$313,628	\$345,491

See accompanying notes to condensed consolidated interim financial statements.

## **Cameco Corporation**

### **Notes to Condensed Consolidated Interim Financial Statements**

(Unaudited)

(\$Cdn thousands except per share amounts and as noted)

#### **1. Cameco Corporation**

Cameco Corporation is incorporated under the Canada Business Corporations Act. The address of its registered office is 2121 11<sup>th</sup> Street West, Saskatoon, Saskatchewan, S7M 1J3. The condensed consolidated interim financial statements as at and for the period ended June 30, 2012 comprise Cameco Corporation and its subsidiaries (collectively, the “Company” or “Cameco”) and the Company’s interest in associates and joint ventures. The Company is primarily engaged in the exploration for and the development, mining, refining, conversion and fabrication of uranium for sale as fuel for generating electricity in nuclear power reactors in Canada and other countries. Cameco has a 31.6% interest in Bruce Power L.P. (“BPLP”), which operates the four Bruce B nuclear reactors in Ontario.

#### **2. Significant Accounting Policies**

##### **(a) Statement of Compliance**

These condensed consolidated interim financial statements have been prepared in accordance with IAS 34, *Interim Financial Reporting*. The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with Cameco’s annual consolidated financial statements as at and for the year ended December 31, 2011.

These condensed consolidated interim financial statements were authorized for issuance by the Company’s board of directors on July 26, 2012.

##### **(b) Basis of Presentation**

These condensed consolidated interim financial statements are presented in Canadian dollars, which is the Company’s functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand except where otherwise noted.

The condensed consolidated interim financial statements have been prepared on the historical cost basis except for the following material items in the statement of financial position: derivative financial instruments, available-for-sale financial assets and liabilities for cash-settled share-based payment arrangements are measured at fair value and the defined benefit asset is recognized as plan assets, plus unrecognized past service cost, less the present value of the defined benefit obligation.

The preparation of the condensed consolidated interim financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may vary from these estimates.

In preparing these condensed consolidated interim financial statements, the significant judgments made by management in applying the Company’s accounting policies and key sources of estimation uncertainty were the same as those that applied to the consolidated financial statements as at and for the year ended December 31, 2011.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, are disclosed in note 6 of the December 31, 2011 consolidated financial statements.

#### **3. Accounting Changes**

##### **(a) New Standards and Interpretations not yet Adopted**

The Company has not yet adopted the standards and amendments to existing standards that have been issued. The standards and amendments, unless otherwise stated, are effective for periods beginning on or after January 1, 2013. Cameco is assessing the impact of the following standards and amendments on its financial statements:

##### **(i) Financial Instruments**

In October 2010, the International Accounting Standards Board (“IASB”) issued IFRS 9, *Financial Instruments* (“IFRS 9”). This standard is part of a wider project to replace IAS 39, *Financial Instruments: Recognition and Measurement* (“IAS 39”). IFRS 9 replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The basis of classification depends on the entity’s business model and the contractual cash flow

characteristics of the financial asset or liability. The guidance in IAS 39 on impairment of financial assets and hedge accounting continues to apply.

**(ii) Consolidated Financial Statements**

In May 2011, the IASB issued IFRS 10, *Consolidated Financial Statements* (“IFRS 10”). This standard establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 defines the principle of control and establishes control as the basis for determining which entities are consolidated in the consolidated financial statements.

**(iii) Joint Arrangements**

In May 2011, the IASB issued IFRS 11, *Joint Arrangements* (“IFRS 11”). This standard establishes principles for financial reporting by parties to a joint arrangement. IFRS 11 requires a party to assess the rights and obligations arising from an arrangement in determining whether an arrangement is either a joint venture or a joint operation. Joint ventures are to be accounted for using the equity method while joint operations will continue to be accounted for using proportionate consolidation.

**(iv) Disclosure of Interests in Other Entities**

In May 2011, the IASB issued IFRS 12, *Disclosure of Interests in Other Entities* (“IFRS 12”). This standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 integrates and makes consistent the disclosure requirements for a reporting entity’s interest in other entities and presents those requirements in a single standard.

**(v) Fair Value Measurement**

In May 2011, the IASB issued IFRS 13, *Fair Value Measurement* (“IFRS 13”). This standard provides additional guidance where IFRS requires fair value to be used. IFRS 13 defines fair value, sets out in a single standard a framework for measuring fair value and establishes the required disclosures about fair value measurements.

**(vi) Employee Benefits**

In June 2011, the IASB issued an amended version of IAS 19, *Employee Benefits* (“IAS 19”). This amendment eliminates the ‘corridor method’ of accounting for defined benefit plans. Revised IAS 19 also streamlines the presentation of changes in assets and liabilities arising from defined benefit plans, and enhances the disclosure requirements for defined benefit plans.

**(vii) Presentation of Other Comprehensive Income (“OCI”)**

In June 2011, the IASB issued an amended version of IAS 1, *Presentation of Financial Statements* (“IAS 1”). This amendment is effective for annual periods beginning on or after July 1, 2012 and requires companies preparing financial statements in accordance with IFRS to group together items within OCI that may be reclassified to the profit or loss section of the statement of earnings. Revised IAS 1 also reaffirms existing requirements that items in OCI and profit or loss should be presented as either a single statement or two consecutive statements.

**(viii) Financial Assets and Financial Liabilities**

In December 2011, the IASB issued amendments to IAS 32, *Financial Instruments: Presentation* (“IAS 32”) and IFRS 7, *Financial Instruments: Disclosures* (“IFRS 7”). The amendments are effective for periods beginning on or after January 1, 2013 for IFRS 7 and January 1, 2014 for IAS 32 and are to be applied retrospectively. These amendments clarify matters regarding offsetting financial assets and financial liabilities as well as related disclosure requirements.



**(b) Accounting for Kintyre**

In August 2008, Cameco acquired a 70% interest in the Kintyre exploration project in Australia. The Company previously consolidated its investment in Kintyre on the basis that it was able to exercise control over the asset. In the second quarter of 2012, the Company reconsidered the accounting treatment applied to Kintyre and concluded that consolidation of the investment was not appropriate and only Cameco's interest in the assets and liabilities of Kintyre should be recognized. Accordingly, the non-controlling interest in the assets, liabilities and expenses has been removed from the financial statements. The change in accounting has been applied retrospectively and the comparative statements for 2011 have been recast. There was no impact on retained earnings or net earnings attributable to equity holders for any of the recast periods. The most significant changes relate to a reduction of property, plant and equipment of \$182,615,000 and a reduction of the non-controlling interest on the balance sheet of \$182,395,000.

**4. Inventories**

	<b>Jun 30/12</b>	<b>Dec 31/11</b>
<b>Uranium</b>		
Concentrate	\$413,241	\$361,481
Broken ore	16,113	14,310
	429,354	375,791
<b>Fuel Services</b>	147,897	118,084
<b>Total</b>	<b>\$577,251</b>	<b>\$493,875</b>

**5. Long-Term Receivables, Investments and Other**

	<b>Jun 30/12</b>	<b>Dec 31/11</b>
<b>BPLP</b>		
Capital lease receivable from Bruce A Limited Partnership ("BALP") <sup>(a)</sup>	\$84,688	\$87,785
Derivatives [note 13]	46,045	54,010
Available-for-sale securities		
GoviEx Uranium (privately held)	21,100	21,057
Derivatives [note 13]	14,032	17,392
Advances receivable from Inkai JV LLP [note 16]	98,064	78,058
Investment tax credits	63,440	54,038
Other	56,106	33,911
	383,475	346,251
Less current portion	(75,101)	(62,433)
<b>Net</b>	<b>\$308,374</b>	<b>\$283,818</b>

<sup>(a)</sup> BPLP leases the Bruce A nuclear generating plants and other property, plant and equipment to BALP under a sublease agreement. Future minimum base rent sublease payments under the capital lease receivable are imputed using a 7.5% discount rate.

## 6. Other Liabilities

	Jun 30/12	Dec 31/11
Deferred sales	\$10,318	\$13,739
Derivatives [note 13]	22,241	28,499
Accrued pension and post-retirement benefit liability	29,493	38,050
BPLP		
Accrued pension and post-retirement benefit liability	474,317	468,363
Derivatives [note 13]	19,247	19,439
Ontario Power Generation ("OPG") loan	3,476	4,045
Other	5,043	6,624
	564,135	578,759
Less current portion	(40,279)	(50,495)
<b>Total</b>	<b>\$523,856</b>	<b>\$528,264</b>

## 7. Share Capital

- (a) At June 30, 2012, there were 395,313,278 common shares outstanding.
- (b) Options in respect of 9,896,605 shares are outstanding under the stock option plan and are exercisable up to 2019. For the quarter ended June 30, 2012, 60,880 options were exercised resulting in the issuance of shares (2011 – 11,488). For the six months ended June 30, 2012, 567,855 options were exercised resulting in the issuance of shares (2011 – 360,040).

## 8. Finance Costs

	Three Months Ended		Six Months Ended	
	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
Interest on long-term debt	\$13,443	\$14,171	\$26,835	\$28,143
Unwinding of discount on provisions	3,413	3,447	6,776	6,738
Other charges	1,652	981	4,043	2,141
Foreign exchange losses (gains)	(5,182)	576	(2,746)	1,317
Interest on short-term debt	425	529	1,111	1,223
Capitalized interest	(1,001)	-	(1,001)	-
<b>Total</b>	<b>\$12,750</b>	<b>\$19,704</b>	<b>\$35,018</b>	<b>\$39,562</b>

## 9. Income Taxes

	Three Months Ended		Six Months Ended	
	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
Earnings (loss) before income taxes				
Canada	\$(84,999)	\$(54,606)	\$(164,344)	\$(74,619)
Foreign	64,046	108,385	267,370	223,690
	<b>\$(20,953)</b>	<b>\$53,779</b>	<b>\$103,026</b>	<b>\$149,071</b>
Current income taxes (recovery)				
Canada	\$(880)	\$6,266	\$534	\$(425)
Foreign	3,331	5,556	14,224	17,136
	<b>\$2,451</b>	<b>\$11,822</b>	<b>\$14,758</b>	<b>\$16,711</b>
Deferred income taxes (recovery)				
Canada	\$(27,023)	\$(20,273)	\$(45,408)	\$(16,756)
Foreign	(3,669)	7,578	(5,159)	2,979
	<b>\$(30,692)</b>	<b>\$(12,695)</b>	<b>\$(50,567)</b>	<b>\$(13,777)</b>
<b>Income tax expense (recovery)</b>	<b>\$(28,241)</b>	<b>\$(873)</b>	<b>\$(35,809)</b>	<b>\$2,934</b>

In 2008, as part of the ongoing annual audits of Cameco's Canadian tax returns, Canada Revenue Agency ("CRA") disputed the transfer pricing methodology used by Cameco and its wholly owned Swiss subsidiary, Cameco Europe Ltd. ("CEL"), in respect of sale and purchase agreements for uranium products. From December 2008 to date, CRA issued notices of reassessment for the taxation years 2003, 2004, 2005 and 2006, which have increased Cameco's income for Canadian income tax purposes by approximately \$43,000,000, \$108,000,000, \$197,000,000 and \$243,000,000 respectively. No reassessment received to date has resulted in more than a nominal amount of cash taxes becoming payable due to the availability of elective deductions and tax loss carrybacks. Cameco believes it is likely that CRA will reassess Cameco's tax returns for subsequent years on a similar basis.

CRA's Transfer Pricing Review Committee has not imposed a transfer pricing penalty for any year reassessed to date.

Having regard to advice from its external advisors, Cameco's opinion is that CRA's position is incorrect, and Cameco is contesting CRA's position. However, to reflect the uncertainties of CRA's appeals process and litigation, Cameco has recorded a cumulative tax provision related to this matter for the years 2003 through the current period in the amount of \$58,000,000. No provisions for penalties or interest have been recorded. Cameco does not expect more than a nominal amount of cash taxes to be payable due to the availability of elective deductions and tax loss carryovers. While the resolution of this matter may result in liabilities that are higher or lower than the reserve, management believes that the ultimate resolution will not be material to Cameco's financial position, results of operations or liquidity over the period. However, an unfavourable outcome for the years 2003 to 2011 could be material to Cameco's financial position, results of operations or cash flows in the year(s) of resolution.

Further to Cameco's decision to contest CRA's reassessments, Cameco is pursuing its appeal rights under the Income Tax Act.

Other comprehensive income included on the consolidated statements of comprehensive income and the consolidated statements of changes in equity is presented net of income taxes. The following income tax amounts are included in each component of other comprehensive income:

**For the three months ended June 30, 2012**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$15,718	\$ -	\$15,718
Losses on derivatives designated as cash flow hedges	(1,833)	458	(1,375)
Gains on derivatives designated as cash flow hedges transferred to net earnings	(8,397)	2,099	(6,298)
Unrealized gains on available-for-sale assets	213	(28)	185
Losses on available-for-sale assets transferred to net earnings	9	(1)	8
	<b>\$5,710</b>	<b>\$2,528</b>	<b>\$8,238</b>

**For the three months ended June 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$6,997	\$ -	\$6,997
Gains on derivatives designated as cash flow hedges	2,023	(512)	1,511
Gains on derivatives designated as cash flow hedges transferred to net earnings	(6,977)	1,875	(5,102)
Unrealized gains on available-for-sale assets	253	(36)	217
Gains on available-for-sale assets transferred to net earnings	(6)	1	(5)
	<b>\$2,290</b>	<b>\$1,328</b>	<b>\$3,618</b>

**For the six months ended June 30, 2012**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$(3,106)	\$ -	\$(3,106)
Gains on derivatives designated as cash flow hedges	7,584	(1,896)	5,688
Gains on derivatives designated as cash flow hedges transferred to net earnings	(15,777)	3,944	(11,833)
Unrealized losses on available-for-sale assets	(105)	15	(90)
Gains on available-for-sale assets transferred to net earnings	(45)	6	(39)
	<b>\$(11,449)</b>	<b>\$2,069</b>	<b>\$(9,380)</b>

**For the six months ended June 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$(14,382)	\$ -	\$(14,382)
Gains on derivatives designated as cash flow hedges	4,273	(1,151)	3,122
Gains on derivatives designated as cash flow hedges transferred to net earnings	(15,341)	4,109	(11,232)
Unrealized gains on available-for-sale assets	791	(107)	684
Gains on available-for-sale assets transferred to net earnings	(2,120)	280	(1,840)
	<b>\$(26,779)</b>	<b>\$3,131</b>	<b>\$(23,648)</b>

**10. Statements of Cash Flows  
Other Operating Items**

	Three Months Ended		Six Months Ended	
	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
Changes in non-cash working capital:				
Accounts receivable	\$(34,449)	\$(18,978)	\$295,102	\$229,650
Inventories	(66,050)	(57,381)	(63,038)	(116,579)
Supplies and prepaid expenses	(23,014)	(9,317)	(16,195)	(4,040)
Accounts payable and accrued liabilities	(23,961)	(15,681)	(70,470)	(39,865)
Other	(13,151)	(5,834)	(34,712)	(24,780)
<b>Total</b>	<b>\$(160,625)</b>	<b>\$(107,191)</b>	<b>\$110,687</b>	<b>\$44,386</b>

**11. Share-Based Compensation Plans**

The Company has the following equity-settled plans:

**(a) Stock Option Plan**

The Company has established a stock option plan under which options to purchase common shares may be granted to employees of Cameco. Options granted under the stock option plan have an exercise price of not less than the closing price quoted on the TSX for the common shares of Cameco on the trading day prior to the date on which the option is granted. The options vest over three years and expire eight years from the date granted.

The aggregate number of common shares that may be issued pursuant to the Cameco stock option plan shall not exceed 43,017,198, of which 27,054,674 shares have been issued.

**(b) Executive Performance Share Unit ("PSU")**

The Company has established a PSU plan whereby it provides each plan participant an annual grant of PSUs in an amount determined by the board. Each PSU represents one phantom common share that entitles the participant to a payment of one Cameco common share purchased on the open market, or cash at the board's discretion, at the end of each three-year period if certain performance and vesting criteria have been met. The final value of the PSUs will be based on the value of Cameco common shares at the end of the three-year period and the number of PSUs that ultimately vest. Vesting of PSUs at the end of the three-year period will be based on total shareholder return over the three years, Cameco's ability to meet its annual cash flow from operations targets and whether the participating executive remains employed by Cameco at the end of the three-year vesting period.

**(c) Executive Restricted Share Unit (“RSU”)**

In 2011, the Company established an RSU plan whereby it provides each plan participant a grant of RSUs in an amount determined by the board. Each RSU represents one phantom common share that entitles the participant to a payment of one Cameco common share purchased on the open market, or cash at the board’s discretion. The final value of the RSUs will be based on the value of Cameco common shares at the end of the three year vesting period.

Cameco records compensation expense with an offsetting credit to contributed surplus to reflect the estimated fair value of the equity-settled share-based compensation plans granted to employees.

	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>Jun 30/12</b>	<b>Jun 30/11</b>	<b>Jun 30/12</b>	<b>Jun 30/11</b>
Stock option plan	\$6,072	\$2,375	\$9,056	\$9,620
Performance share unit	1,486	850	573	1,700
Restricted share unit	148	-	297	-
<b>Total</b>	<b>\$7,706</b>	<b>\$3,225</b>	<b>\$9,926</b>	<b>\$11,320</b>

The fair value of the units granted through the PSU plan was determined based on Monte Carlo simulation. The fair value of all other share-based payment plans was measured based on the Black-Scholes option-pricing model. Expected volatility is estimated by considering historic average share price volatility. The inputs used in the measurement of the fair values at grant date were as follows:

	<b>Stock Option Plan</b>	<b>PSUs</b>
Number of options granted	2,097,573	178,640
Average strike price	\$21.14	-
Expected dividend	\$0.40	\$0.40
Expected volatility	47%	36%
Risk-free interest rate	1.4%	1.4%
Expected life of option	4.3 years	3 years
Expected forfeitures	10%	0%
Weighted average grant date fair values	\$7.21	\$20.05

In addition to these inputs, other features of the PSU grant were incorporated into the measurement of fair value. The market condition based on total shareholder return was incorporated by utilizing a Monte Carlo simulation. The non-market criteria relating to realized selling prices, production targets and cost control have been incorporated into the valuation at grant date by reviewing prior history and corporate budgets.

## 12. Commitments and Contingencies

- (a) On May 16, 2012, Cameco, Cameco Bruce Holdings II Inc., BPC Generation Infrastructure Trust (“BPC”) and TransCanada Pipelines Limited (“TransCanada”) (collectively, the "Consortium") received an arbitration award in their favour against British Energy Limited and British Energy International Holdings Limited (collectively, “BE”) ruling in favour of the Consortium on the issues of repair costs and lost revenue for breach of a representation and warranty contained in the February 14, 2003 Amended and Restated Master Purchase Agreement under which the Consortium acquired BE’s interest in BPLP. The Consortium and BE are in discussions over the quantification of the damages under the arbitrators award. If these issues are not resolved, they will be referred back to the arbitrator for a final decision. The Company recorded an estimate of the expected net proceeds.

In connection with this arbitration, BE issued on February 10, 2006, and then served on OPG and BPLP a Statement of Claim. This Statement of Claim seeks damages for any amounts that BE is found liable to pay to the Consortium in connection with the Unit 8 steam generator arbitration described above, damages in the amount of \$500,000,000, costs and pre and post judgment interest amongst other things. Further proceedings in this action are on hold pending final disposition of the arbitration award.

- (b) Annual supplemental rents of \$30,000,000 (subject to CPI) per operating reactor are payable by BPLP to OPG. Should the hourly annual average price of electricity in Ontario fall below \$30 per megawatt hour for any calendar year, the supplemental rent reduces to \$12,000,000 per operating reactor. In accordance with the Sublease Agreement, BALP will participate in its share of any adjustments to the supplemental rent.
- (c) Cameco, TransCanada and BPC have assumed the obligations to provide financial guarantees on behalf of BPLP. Cameco has provided the following financial assurances, with varying terms that range from 2012 to 2018:
- i) Guarantees to customers under power sales agreements of up to \$19,000,000. At June 30, 2012, Cameco’s actual exposure under these agreements was \$6,500,000.
  - ii) Termination payments to OPG pursuant to the lease agreement of \$58,300,000. The fair value of these guarantees is nominal.
- (d) Under a supply contract with the Ontario Power Authority (“OPA”), BPLP is entitled to receive payments from the OPA during periods when the market price for electricity in Ontario is lower than the floor price defined under the agreement during a calendar year. On July 6, 2009, BPLP and the OPA amended the supply contract such that beginning in 2009, the annual payments received will not be subject to repayment in future years. Previously, the payments received under the agreement were subject to repayment during the entire term of the contract, dependent on the spot price in future periods. BPLP’s entitlement to receive these payments remains in effect until December 31, 2019 but the generation that is subject to these payments starts to decrease in 2016, reflecting the original estimated lives for the Bruce B units. During 2012, BPLP recorded \$409,400,000 under this agreement which was recognized as revenue with Cameco’s share being \$129,400,000.

### 13. Derivatives

The following tables summarize the fair value of derivatives and classification on the statements of financial position:

#### As at June 30, 2012

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$74	\$7,443	\$7,517
Foreign currency contracts	(13,811)	-	(13,811)
Interest rate contracts	5,528	-	5,528
Cash flow hedges:			
Energy and sales contracts	-	19,355	19,355
<b>Net</b>	<b>\$(8,209)</b>	<b>\$26,798</b>	<b>\$18,589</b>
Classification:			
Current portion of long-term receivables, investments and other [note 5]	\$7,110	\$37,166	\$44,276
Long-term receivables, investments and other [note 5]	6,922	8,879	15,801
Current portion of other liabilities [note 6]	(18,826)	(17,097)	(35,923)
Other liabilities [note 6]	(3,415)	(2,150)	(5,565)
<b>Net</b>	<b>\$(8,209)</b>	<b>\$26,798</b>	<b>\$18,589</b>

#### As at December 31, 2011

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(639)	\$8,033	\$7,394
Foreign currency contracts	(17,633)	-	(17,633)
Interest rate contracts	7,165	-	7,165
Cash flow hedges:			
Energy and sales contracts	-	26,538	26,538
<b>Net</b>	<b>\$(11,107)</b>	<b>\$34,571</b>	<b>\$23,464</b>
Classification:			
Current portion of long-term receivables, investments and other [note 5]	\$8,922	\$42,088	\$51,010
Long-term receivables, investments and other [note 5]	8,470	11,922	20,392
Current portion of other liabilities [note 6]	(26,555)	(16,913)	(43,468)
Other liabilities [note 6]	(1,944)	(2,526)	(4,470)
<b>Net</b>	<b>\$(11,107)</b>	<b>\$34,571</b>	<b>\$23,464</b>



The following tables summarize different components of the gains (losses) on derivatives:

**For the three months ended June 30, 2012**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(205)	\$(492)	\$(697)
Foreign currency contracts	(22,454)	-	(22,454)
Interest rate contracts	1,272	-	1,272
Cash flow hedges:			
Energy and sales contracts	-	(1,001)	(1,001)
<b>Net</b>	<b>\$(21,387)</b>	<b>\$(1,493)</b>	<b>\$(22,880)</b>

**For the three months ended June 30, 2011**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(101)	\$464	\$363
Foreign currency contracts	10,223	-	10,223
Interest rate contracts	2,642	-	2,642
Cash flow hedges:			
Energy and sales contracts	-	(1,369)	(1,369)
<b>Net</b>	<b>\$12,764</b>	<b>\$(905)</b>	<b>\$11,859</b>

**For the six months ended June 30, 2012**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$125	\$1,593	\$1,718
Foreign currency contracts	1,433	-	1,433
Interest rate contracts	(403)	-	(403)
Cash flow hedges:			
Energy and sales contracts	-	(1,174)	(1,174)
<b>Net</b>	<b>\$1,155</b>	<b>\$419</b>	<b>\$1,574</b>

**For the six months ended June 30, 2011**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$1,372	\$138	\$1,510
Foreign currency contracts	33,660	-	33,660
Interest rate contracts	1,873	-	1,873
Cash flow hedges:			
Energy and sales contracts	-	(1,455)	(1,455)
<b>Net</b>	<b>\$36,905</b>	<b>\$(1,317)</b>	<b>\$35,588</b>

Over the next 12 months, based on current exchange rates, Cameco expects an estimated \$15,110,000 of pre-tax gains from BPLP's various energy and sales related cash flow hedges to be reclassified through other comprehensive income to net earnings. The maximum length of time BPLP is hedging its exposure to the variability in future cash flows related to electricity prices on future transactions is six years.

#### 14. Earnings Per Share

Per share amounts have been calculated based on the weighted average number of common shares outstanding during the period. The weighted average number of paid shares outstanding in 2012 was 395,121,999 (2011 – 394,607,145).

	Three Months Ended		Six Months Ended	
	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
<b>Basic earnings per share computation</b>				
Net earnings attributable to equity holders	\$7,877	\$54,652	\$139,615	\$146,137
Weighted average common shares outstanding	395,277	394,706	395,122	394,607
<b>Basic earnings per common share</b>	<b>\$0.02</b>	<b>\$0.14</b>	<b>\$0.35</b>	<b>\$0.37</b>
<b>Diluted earnings per share computation</b>				
Net earnings attributable to equity holders	\$7,877	\$54,652	\$139,615	\$146,137
Weighted average common shares outstanding	395,277	394,706	395,122	394,607
Dilutive effect of stock options	94	667	568	1,335
Weighted average common shares outstanding, assuming dilution	395,371	395,373	395,690	395,942
<b>Diluted earnings per common share</b>	<b>\$0.02</b>	<b>\$0.14</b>	<b>\$0.35</b>	<b>\$0.37</b>

## 15. Segmented Information

Cameco has three reportable segments: uranium, fuel services and electricity. The uranium segment involves the exploration for, mining, milling, purchase and sale of uranium concentrate. The fuel services segment involves the refining, conversion and fabrication of uranium concentrate and the purchase and sale of conversion services. The electricity segment involves the generation and sale of electricity.

Cameco's reportable segments are strategic business units with different products, processes and marketing strategies.

Accounting policies used in each segment are consistent with the policies outlined in the most recent annual consolidated financial statements. Segment revenues, expenses and results include transactions between segments incurred in the ordinary course of business. These transactions are priced on an arm's length basis and are eliminated on consolidation.

### (a) Business Segments

#### For the three months ended June 30, 2012

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$205,503	\$66,207	\$119,132	\$582	\$391,424
Expenses					
Cost of products and services sold	130,673	51,169	44,273	78	226,193
Depreciation and amortization	32,373	5,870	19,748	3,844	61,835
<b>Cost of sales</b>	<b>163,046</b>	<b>57,039</b>	<b>64,021</b>	<b>3,922</b>	<b>288,028</b>
<b>Gross profit (loss)</b>	<b>42,457</b>	<b>9,168</b>	<b>55,111</b>	<b>(3,340)</b>	<b>103,396</b>
Exploration	17,888	-	-	-	17,888
Loss on sale of assets	913	-	-	-	913
Share of loss from equity-accounted investees	1,253	706	-	-	1,959
Other expense	36,507	-	-	-	36,507
Non-segmented expenses					67,082
<b>Earnings (loss) before income taxes</b>	<b>(14,104)</b>	<b>8,462</b>	<b>55,111</b>	<b>(3,340)</b>	<b>(20,953)</b>
Income tax recovery					(28,241)
<b>Net earnings</b>					<b>\$7,288</b>

**For the three months ended June 30, 2011**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$256,261	\$69,606	\$99,224	\$614	\$425,705
Expenses					
Cost of products and services sold	148,139	51,094	68,752	74	268,059
Depreciation and amortization	22,449	5,947	16,845	4,475	49,716
<b>Cost of sales</b>	<b>170,588</b>	<b>57,041</b>	<b>85,597</b>	<b>4,549</b>	<b>317,775</b>
<b>Gross profit (loss)</b>	<b>85,673</b>	<b>12,565</b>	<b>13,627</b>	<b>(3,935)</b>	<b>107,930</b>
Exploration	14,647	-	-	-	14,647
Loss on sale of assets	719	-	-	-	719
Share of loss from equity-accounted investees	1,951	373	-	-	2,324
Other expense	133	-	-	-	133
Non-segmented expenses					36,328
<b>Earnings (loss) before income taxes</b>	<b>68,223</b>	<b>12,192</b>	<b>13,627</b>	<b>(3,935)</b>	<b>53,779</b>
Income tax recovery					(873)
<b>Net earnings</b>					<b>\$54,652</b>

**For the six months ended June 30, 2012**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$606,581	\$122,452	\$224,518	\$1,131	\$954,682
Expenses					
Cost of products and services sold	358,818	92,237	101,338	146	552,539
Depreciation and amortization	63,816	10,108	38,948	7,958	120,830
<b>Cost of sales</b>	<b>422,634</b>	<b>102,345</b>	<b>140,286</b>	<b>8,104</b>	<b>673,369</b>
<b>Gross profit (loss)</b>	<b>183,947</b>	<b>20,107</b>	<b>84,232</b>	<b>(6,973)</b>	<b>281,313</b>
Exploration	40,857	-	-	-	40,857
Gain on sale of assets	(2,149)	-	-	-	(2,149)
Share of loss from equity-accounted investees	1,277	1,494	-	-	2,771
Other expense	35,744	-	-	-	35,744
Non-segmented expenses					101,064
<b>Earnings (loss) before income taxes</b>	<b>108,218</b>	<b>18,613</b>	<b>84,232</b>	<b>(6,973)</b>	<b>103,026</b>
Income tax recovery					(35,809)
<b>Net earnings</b>					<b>\$138,835</b>

**For the six months ended June 30, 2011**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$553,569	\$118,855	\$206,632	\$7,750	\$886,806
Expenses					
Cost of products and services sold	322,792	89,089	124,828	6,915	543,624
Depreciation and amortization	44,798	10,439	34,558	8,992	98,787
<b>Cost of sales</b>	<b>367,590</b>	<b>99,528</b>	<b>159,386</b>	<b>15,907</b>	<b>642,411</b>
<b>Gross profit (loss)</b>	<b>185,979</b>	<b>19,327</b>	<b>47,246</b>	<b>(8,157)</b>	<b>244,395</b>
Exploration	30,486	-	-	-	30,486
Loss on sale of assets	695	-	-	-	695
Share of loss from equity-accounted investees	3,866	1,150	-	-	5,016
Other income	(1,439)	-	-	-	(1,439)
Non-segmented expenses					60,566
<b>Earnings (loss) before income taxes</b>	<b>152,371</b>	<b>18,177</b>	<b>47,246</b>	<b>(8,157)</b>	<b>149,071</b>
Income tax expense					2,934
<b>Net earnings</b>					<b>\$146,137</b>

**16. Related Parties**

The shares of Cameco are widely held and no shareholder, resident in Canada, is allowed to own more than 25% of the Company's outstanding common shares, either individually or together with associates. A non-resident of Canada is not allowed to own more than 15%.

**Transactions with Key Management Personnel**

Key management personnel are those persons that have the authority and responsibility for planning, directing and controlling the activities of the Company, directly or indirectly. Key management personnel of the Company include executive officers, vice-presidents, other senior managers and members of the board of directors.

Certain key management personnel, or their related parties, hold positions in other entities that result in them having control or significant influence over the financial or operating policies of those entities. As noted below, one of these entities transacted with the Company in the reporting period. The terms and conditions of the transactions were on an arm's length basis.

Cameco purchases a significant amount of goods and services for its Saskatchewan mining operations from northern Saskatchewan suppliers to support economic development in the region. One such supplier is Points Athabasca Contracting Ltd. and the president of the company became a member of the board of directors of Cameco during 2009. In 2012, Cameco paid Points Athabasca Contracting Ltd. \$22,000,000 (2011 - \$32,900,000) for construction and contracting services. The transactions were conducted in the normal course of business and were accounted for at the exchange amount. Accounts payable include a balance of \$1,560,000 (2011 - \$6,840,000).

## Other Related Party Transactions

	Transaction Value		Transaction Value		Balance Outstanding	
	Three Months Ended		Six Months Ended		As at	
	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11	Jun 30/12	Jun 30/11
<b>Sale of goods and services</b>						
Jointly Controlled Entities						
BPLP <sup>(a)</sup>	\$22,057	\$6,726	\$38,853	\$22,217	\$29,376	\$7,806
<b>Other</b>						
Jointly Controlled Entities						
Interest income (Inkai)	562	567	1,071	1,203	98,064	97,136
Associates						
Interest expense	(274)	(509)	(671)	(1,035)	(58,647)	(76,790)

(a) Disclosures in respect of transactions with jointly controlled entities represent the amount of such transactions which do not eliminate on proportionate consolidation.

Cameco has entered into fuel supply agreements with BPLP for the procurement of fabricated fuel. Under these agreements, Cameco will supply uranium, conversion services and fabrication services. Contract terms are at market rates and on normal trade terms.

Through an unsecured shareholder loan, Cameco has agreed to fund the development of the Inkai project. The limit of the advances of the loan facility is currently \$263,150,000 (US) and bear interest at a rate of LIBOR plus 2%. At June 30, 2012, \$240,600,000 (US) of principal and interest was outstanding (December 31, 2011 - \$191,900,000 (US)). At June 30, 2012 the remaining funds available for advance under the facility was \$23,000,000 (US) (December 31, 2011 - \$14,200,000 (US)).

In 2008, a promissory note in the amount of \$73,344,000 (US) was issued to finance the acquisition of GE-Hitachi Global Laser Enrichment LLC (GLE). The promissory note is payable on demand and bears interest at market rates. At June 30, 2012, \$57,500,000 (US) of principal and interest was outstanding (December 31, 2011 - \$72,200,000 (US)).

### 17. NUKEM Energy GmbH (“NUKEM”)

On May 14, 2012, Cameco entered into an agreement with Advent International (“Advent”) to purchase NUKEM, one of the world’s leading traders and brokers of nuclear fuel products and services, for cash proceeds of \$136,000,000 (US) and the assumption of their debt. The agreement provides that Cameco will receive the benefits of owning NUKEM as of January 1, 2012. It also includes provisions that would provide Advent with a share of NUKEM’s future earnings under certain conditions until the end of 2014. The agreement is subject to regulatory approvals and is expected to close in the third quarter of 2012.

### 18. Millennium Project Agreement

On June 11, 2012, Cameco acquired a 27.94% interest in the Millennium project from AREVA Resources Canada Inc. (“AREVA”) for \$150,000,000, increasing its ownership to 69.9%. The remaining 30.1% is owned by JCU (Canada) Exploration Co. The Millennium project is a proposed uranium mine located in the Athabasca Basin of northern Saskatchewan consisting of 590 hectares of land. Exploration on the Millennium project area has identified indicated resources of 50,900,000 pounds of U<sub>3</sub>O<sub>8</sub> and inferred resources of 16,700,000 pounds of U<sub>3</sub>O<sub>8</sub>. The terms of the purchase agreement provides AREVA with a 4% royalty on revenue from 27.94% of any production that exceeds 63,000,000 pounds U<sub>3</sub>O<sub>8</sub> from this project.

### 19. Comparative Figures

Certain prior period balances have been reclassified to conform to the current financial statement presentation.