



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

for the quarter ended September 30, 2011

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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 September 30, 2011 (interim financial statements). The information is based on what we knew as of November 4, 2011 and updates our first and second quarter MD&A and annual MD&A included in our 2010 annual financial report.

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, 2010 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.

Effective January 1, 2011, we adopted International Financial Reporting Standards (IFRS) for Canadian publicly accountable enterprises. Our interim financial statements for the first, second and third quarters of 2011 have been prepared using IFRS. Amounts relating to the year ended December 31, 2010 in this MD&A and our interim financial statements have been recast to reflect our adoption of IFRS. Amounts for periods prior to January 1, 2010 are presented in accordance with Canadian Generally Accepted Accounting Principles (Canadian GAAP).

Financial information provided in this MD&A and our interim financial statements has been prepared using IFRS standards and interpretations currently issued and expected to be effective at the end of our first annual IFRS reporting period, which will be December 31, 2011. However, certain accounting policies may not be adopted or the application of such policies to certain transactions or circumstances may be modified. As a result, financial information contained in this MD&A and our interim financial statements is subject to change.

Presentation and terminology used in our interim financial statements and this MD&A differ from that used in previous years. Details of the more significant accounting differences can be found in note 3 to our interim financial statements.

To help you distinguish and understand the impact of the transition to IFRS on our interim financial statements, where we refer to "Canadian GAAP" in this MD&A, we mean Canadian GAAP before the adoption of IFRS.

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 below).
- 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 page 3. We recommend you also review our annual information form and our annual 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 expectations about 2011 and future global uranium supply, consumption, demand and number of operating reactors, including the discussion on the expected impact resulting from the March 2011 nuclear incident in Japan
- our strategy for doubling annual production by 2018 to 40 million pounds is on track and our expectation that existing cash balances and operating cash flows will meet anticipated requirements without the need for any significant additional funding
- our expectation that uranium demand in the near term will remain discretionary
- the outlook for each of our operating segments for 2011, and our consolidated outlook for the year
- our expectation that fourth quarter deliveries will account for over one-third of 2011 sales volumes
- our expectation that we will invest significantly in expanding production at existing mines and advancing projects as we pursue our growth strategy
- our expectation that cash balances will decline as we use the funds in our business and pursue our growth plans
- our expectation that we will have a solid revenue stream for years to come, even in the event of declining uranium market prices
- our expectation that our operating and investment activities for the remainder of 2011 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 2011 to 2015
- our future plans for each of our uranium operating properties, development projects and projects under evaluation, and fuel services operating sites
- our mid-2013 target for initial production from 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
- 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 inaccurate, 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, 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
- we are delayed or do not succeed in remediating and developing Cigar Lake
- 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, lack of tailings capacity, labour shortages, labour relations issues, strikes or lockouts, underground floods, cave ins, tailings dam failures, and other development and operating risks

## 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 costs
- our expectations regarding spot prices and realized prices for uranium, and other factors discussed on page 18 & 19, *Price sensitivity analysis: uranium*
- our expectations regarding tax rates, foreign currency exchange rates and interest rates
- our decommissioning and reclamation expenses
- our mineral reserve and resource estimates
- the geological, hydrological and other conditions at our mines
- our Cigar Lake remediation, development and production plans succeed
- 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, 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, tailings dam failure, lack of tailings capacity, or other development or operating risks

## Our strategy

Our strategy to double annual uranium production to 40 million pounds by 2018 is on track. We are preparing our assets to ensure we have the flexibility to respond appropriately to evolving market conditions. We remain confident in the long-term fundamentals of the nuclear industry, despite near- to medium-term uncertainty. World demand for safe, clean, reliable and affordable energy continues to grow and the need for nuclear as part of the world's energy mix remains as compelling as ever.

We continue to focus on cost-competitiveness and operational efficiency, including in our fuel services business. We are exploring options to extend the operating life of the four B units at Bruce Power.

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.

## Third quarter update

### Our performance

Highlights (\$ millions except where indicated)			Three months ended September 30			Nine months ended September 30		
			2011	2010	change	2011	2010	change
Revenue			527	419	26%	1,407	1,450	(3)%
Gross profit			179	156	15%	423	519	(18)%
Net earnings			39	98	(60)%	186	311	(40)%
\$ per common share (diluted)			0.10	0.25	(60)%	0.47	0.79	(41)%
Adjusted net earnings (non-IFRS/GAAP measure, see pages 10 & 11)			104	80	30%	259	307	(16)%
\$ per common share (adjusted and diluted)			0.26	0.20	30%	0.66	0.78	(15)%
Cash provided by operations (after working capital changes)			190	(5)	3900%	477	412	16%
Average realized prices	Uranium	\$US/lb	47.33	40.63	16%	47.06	41.46	14%
		\$Cdn/lb	45.97	43.01	7%	46.36	43.90	6%
	Fuel services	\$Cdn/kgU	17.42	16.32	7%	18.05	18.19	(1)%
	Electricity	\$Cdn/MWh	54.00	57.00	(5)%	54.00	58.00	(7)%

### Third quarter

Net earnings attributable to our shareholders (net earnings) this quarter were \$39 million (\$0.10 per share diluted) compared to \$98 million (\$0.25 per share diluted) in the third quarter of 2010. Net earnings were down this quarter primarily as a result of losses on foreign exchange derivatives compared to gains in 2010, partially offset by lower income taxes and the item noted below. The Canadian dollar weakened in the third quarter of 2011 relative to the US dollar, while it strengthened in the third quarter of 2010.

On an adjusted basis, our earnings this quarter were \$104 million (\$0.26 per share diluted) compared to \$80 million (\$0.20 per share diluted) (non-IFRS/GAAP measure, see pages 10 and 11) in the third quarter of 2010 mainly due to:

- higher earnings from our uranium business based on higher sales volumes and higher realized prices, partially offset by an increase in the average cost of product sold

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

## First nine months

Net earnings in the first nine months of the year were \$186 million (\$0.47 per share diluted) compared to \$311 million (\$0.79 per share diluted) in the first nine months of 2010. Net earnings were lower than in 2010 mainly as a result of the items noted below along with losses on foreign exchange derivatives compared to gains in 2010, partially offset by lower income taxes.

On an adjusted basis, our earnings for the first nine months of this year were \$259 million (\$0.66 per share diluted) compared to \$307 million (\$0.78 per share diluted) (non-IFRS/GAAP measure, see pages 10 and 11) mainly due to:

- lower earnings from our electricity business due to lower realized prices, higher costs, and a decline in sales
- lower earnings from our uranium business based on an increase in the average cost of product sold and lower sales volumes, partially offset by an increase in the realized price
- lower earnings from our fuel services business as a result of an increase in the average cost of product sold and lower realized prices

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

## Operations update

Highlights		Three months ended September 30			Nine months ended September 30		
		2011	2010	change	2011	2010	change
Uranium	Production volume (million lbs)	<b>5.3</b>	5.6	(5)%	<b>15.8</b>	16.5	(4)%
	Sales volume (million lbs)	<b>7.2</b>	5.6	29%	<b>19.1</b>	20.5	(7)%
	Revenue (\$ millions)	<b>332</b>	240	38%	<b>885</b>	901	(2)%
Fuel services	Production volume (million kgU)	<b>2.8</b>	2.3	22%	<b>11.6</b>	11.7	(1)%
	Sales volume (million kgU)	<b>4.6</b>	3.9	18%	<b>11.1</b>	10.7	4%
	Revenue (\$ millions)	<b>81</b>	64	27%	<b>199</b>	195	2%
Electricity	Output (100%) (TWh)	<b>6.7</b>	6.3	6%	<b>18.7</b>	19.3	(3)%
	Revenue (100%) (\$ millions)	<b>362</b>	363	-	<b>1,016</b>	1,116	(9)%
	Our share of earnings before taxes (\$ millions)	<b>35</b>	36	(3)%	<b>75</b>	123	(39)%

Production in our uranium segment this quarter was down 5% compared to the third quarter of 2010 mainly due to lower production from Smith Ranch-Highland and Inkai. In the first nine months of the year uranium production was down 4% compared to 2010. We have revised our production outlook down 1% for the year due to lower expected production at our US and Inkai operations, partially offset by higher expected production at McArthur River/Key Lake. See *Uranium 2011 Q3 updates* for more information.

### Key highlights:

- signed a non-binding memorandum of understanding (MOU) to process all Cigar Lake ore at McClean Lake mill, which is expected to result in a significant reduction in the operating cost of the project. See page 26 for more information.
- signed a memorandum of agreement (MOA) to increase production at Inkai from 3.9 to 5.2 million pounds (100% basis). See page 26 for more information.

Production in our fuel services segment was 22% higher this quarter than it was in the third quarter of 2010 due to the planned maintenance shutdown of the Port Hope UF<sub>6</sub> plant in 2010. Production for the first nine months of the year was 11.6 million kgU compared to 11.7 million kgU in 2010. Due to current unfavourable market conditions for UF<sub>6</sub> conversion, we are reducing production for this year. We now expect fuel services to produce between 14 million and 15 million kgU this year (previously 15 million to 16 million kgU).

In our electricity segment, BPLP's generation was 6% higher for the quarter and 3% lower for the first nine months of the year, compared to the same periods last year. The capacity factor this quarter was 93% and 87% for the first nine months of the year.

Also of note this quarter:

On August 30, 2011, we made an all-cash offer to acquire all the outstanding shares of Hathor Exploration Limited (Hathor) for a price of \$3.75 per share in a transaction which values the fully diluted share capital of Hathor at approximately \$520 million.<sup>1</sup>

On October 19, 2011, Hathor announced that it had entered into an agreement with Rio Tinto pursuant to which Rio Tinto will make an offer for all of the common shares of Hathor. Rio Tinto subsequently made its offer.

We are reviewing the Hathor announcement and Rio Tinto offer. On October 31, 2011, we announced the extension of the expiry date of our offer to November 14, 2011.

## Uranium market update

The uranium market during the third quarter can be characterized as uncertain. We expect this uncertainty to continue in the near to medium term as the industry continues to determine the extent to which short- to medium-term demand has been impacted by the March nuclear incident in Japan. The biggest drivers of uncertainty are concerns about excess German and Japanese uranium inventories and the extent to which deferrals and/or cancellations under sales contracts will introduce additional volumes into the market.

Germany, which has 17 nuclear reactors and represents 5% of the global generating capacity, has decided to revert to its previous phase out policy. Currently, eight of its reactors (about 2% of global generating capacity) are shutdown; we do not expect these reactors to restart. Germany has indicated it plans to shut down the remaining nine reactors by 2022.

In Japan, 11 of its 54 nuclear reactors are currently operating. Many of the reactors currently off-line were unaffected by the March earthquake and tsunami; however, they require regulatory and political approvals before they can restart (four of the Fukushima-Daiichi units are permanently shut down). There is concern that these approvals may be delayed due to decreased public support for nuclear in Japan. However, there has been some progress. In August, the local government approved the restart of the first nuclear reactor since March—Hokkaido's Tomari 3 reactor. Japan's 54 reactors represent 12% of global nuclear generating capacity.

Despite the near- to medium-term uncertainty, in the long term we continue to see a very strong and promising growth profile for the nuclear industry. Countries around the world, with very few exceptions, have reconfirmed their commitment to nuclear energy. China, India, France, Russia, South Korea, the United Kingdom, Canada, the United States, and almost every other country with a nuclear program are maintaining nuclear as a part of their energy mix.

Other previously non-nuclear countries are either moving ahead with their reactor construction programs or considering adding nuclear to their energy programs in the future. For example, the United Arab Emirates is proceeding with its plans to have 5.6 gigawatts of nuclear capacity in place by 2020 and is beginning the process to secure fuel for those reactors. In Saudi Arabia, where power demand has been increasing by 7% to 8% annually, plans to build 16 reactors by 2030 have been announced.

We are in the enviable position of being heavily committed under long-term sales contracts until 2016. With more than 300 million pounds of uranium under contract, we expect to have a solid revenue stream for years to come, even in the event of declining uranium market prices. With a target of 40% fixed-price contracts and 60% market-related, our portfolio is designed to give us increasing leverage when uranium prices increase, and to protect us when prices decline.

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<sup>1</sup> Estimated fully diluted share capital of approximately 139 million shares, based on Hathor's public disclosure.

## Caution about forward-looking information relating to the March 2011 Japanese nuclear incident

This discussion of the expected impact of the March 2011 nuclear incident in Japan, including its potential impact on future global uranium demand and the number of operating 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 2.

## Industry prices

	Sep 30 2011	Jun 30 2011	Mar 31 2011	Sept 30 2010	Jun 30 2010	Mar 31 2010
<b>Uranium</b> (\$US/lb U <sub>3</sub> O <sub>8</sub> ) <sup>1</sup>						
Average spot market price	<b>52.25</b>	52.88	60.50	46.63	41.75	41.88
Average long-term price	<b>63.50</b>	68.00	70.00	61.00	59.00	59.00
<b>Fuel services</b> (\$US/kgU UF <sub>6</sub> ) <sup>1</sup>						
Average spot market price						
• North America	<b>9.50</b>	11.00	12.00	13.00	7.00	5.63
• Europe	<b>9.50</b>	11.00	12.00	12.50	7.88	7.50
Average long-term price						
• North America	<b>16.50</b>	16.00	15.75	13.13	11.25	11.00
• Europe	<b>17.00</b>	16.25	16.00	13.50	12.75	12.75
Note: the industry does not publish UO <sub>2</sub> prices.						
<b>Electricity</b> (\$/MWh)						
Average Ontario electricity spot price	<b>33.00</b>	28.00	32.00	43.00	34.00	34.00

<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 third quarter of 2011 was about 11.8 million pounds. This compares to about 13.3 million pounds in the third quarter of 2010. For the first nine months of the year, spot purchases totalled 40.1 million pounds compared to 36 million pounds for the same period in 2010.

Continued uncertainty put downward pressure on the spot price. At the end of the quarter, the average spot price was \$52.25 (US) per pound. On October 31, 2011 Ux reported a spot price of \$52.00 (US) per pound. Demand remains extremely discretionary and buyers are very price sensitive.

The long-term uranium price declined 7% 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).

In general, utilities are well covered under existing contracts and have been building inventory levels of U<sub>3</sub>O<sub>8</sub> since 2004, so we expect uranium demand in the near term to remain discretionary.

Spot market UF<sub>6</sub> conversion prices declined, while long-term UF<sub>6</sub> conversion price indicators increased 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 seen as 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 November 4, 2011, we had:

- 394,717,683 common shares and one Class B share outstanding
- 8,601,319 stock options outstanding, with exercise prices ranging from \$10.51 to \$46.88

### 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.

<b>2011 Q3 results</b>	
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### Consolidated financial results

Effective January 1, 2011, we adopted IFRS for Canadian publicly accountable enterprises. Our interim financial statements have been prepared using IFRS. Amounts relating to the year ended December 31, 2010 in this MD&A and our related interim financial statements have been recast to reflect our adoption of IFRS. Amounts for periods prior to January 1, 2010 are presented in accordance with Canadian GAAP.

Highlights (\$ millions except per share amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
Revenue	527	419	26%	1,407	1,450	(3)%
Net earnings	39	98	(60)%	186	311	(40)%
\$ per common share (basic)	0.10	0.25	(60)%	0.47	0.79	(41)%
\$ per common share (diluted)	0.10	0.25	(60)%	0.47	0.79	(41)%
Adjusted net earnings (non-IFRS/GAAP measure, see pages 10 & 11)	104	80	30%	259	307	(16)%
\$ per common share (adjusted and diluted)	0.26	0.20	30%	0.66	0.78	(15)%
Cash provided by operations (after working capital changes)	190	(5)	3900%	477	412	16%

### Net earnings

Net earnings this quarter were \$39 million (\$0.10 per share diluted) compared to \$98 million (\$0.25 per share diluted) in the third quarter of 2010, primarily as a result of:

- losses on foreign exchange derivatives, compared to gains in 2010
- lower income taxes
- higher earnings from our uranium business based on higher sales and higher realized prices, partially offset by an increase in the average cost of product sold

Net earnings in the first nine months of the year were \$186 million (\$0.47 per share diluted) compared to \$311 million (\$0.79 per share diluted) in the first nine months of 2010 mainly due to:

- lower earnings from our electricity business due to lower realized prices, higher costs and a decline in sales
- lower earnings from our uranium business based on an increase in the cost of product sold and lower sales volumes, partially offset by an increase in the realized price
- lower earnings from our fuel services business as a result of an increase in the average cost of product sold
- losses on foreign exchange derivatives, compared to gains in 2010
- lower income taxes

The following table shows the items that contribute to the difference between our Canadian GAAP and IFRS earnings for the three months and nine months ended September 30, 2010. For more information about these accounting differences see note 3 to our interim financial statements.

2010 changes in earnings (\$ millions)	Three months ended September 30	Nine months ended September 30
<b>Net earnings – Canadian GAAP</b>	<b>98</b>	<b>308</b>
<b>Accounting differences</b>		
Borrowing costs	(11)	(32)
Decommissioning provision	1	2
In-process research & development	3	9
BPLP – pension and maintenance costs	(2)	6
Income taxes – tax effect on differences	1	4
Income taxes – IFRS accounting difference	8	14
<b>Total accounting differences</b>	<b>-</b>	<b>3</b>
<b>Net earnings – IFRS</b>	<b>98</b>	<b>311</b>

### Adjusted net earnings (non-IFRS/GAAP measures)

Adjusted net earnings is a measure with no standardized meaning under IFRS (non-IFRS measure). We use this measure as a more meaningful way to compare our financial performance from period to period. Adjusted net earnings is our net earnings 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. We also used this measure prior to adoption of IFRS (non-GAAP measure).

Adjusted net earnings is non-standard supplemental information, and not a substitute for financial information prepared according to accounting standards. Other companies may calculate this measure differently. The table below reconciles adjusted net earnings with our net earnings.

(\$ millions)	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Net earnings	39	98	186	311
Adjustments on derivatives (after tax) <sup>1</sup>	65	(18)	73	(4)
Adjusted net earnings	104	80	259	307

<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 as reported under IFRS 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 and for the first nine months of the year.

<b>Change in adjusted net earnings</b> (\$ millions)		<b>Three months</b> <b>ended September 30</b>	<b>Nine months</b> <b>ended September 30</b>
<b>Adjusted net earnings – 2010</b>		<b>80</b>	<b>307</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, depletion and reclamation (DDR))			
Uranium	Higher (lower) sales volumes	32	(24)
	Higher realized prices (\$US)	51	113
	Foreign exchange impact on realized prices	(30)	(66)
	Higher costs	(29)	(47)
change - uranium		24	(24)
Fuel services	Higher sales volumes	2	2
	Higher (lower) realized prices (\$Cdn)	5	(2)
	Higher costs	(8)	(23)
change – fuel services		(1)	(23)
Electricity	Higher (lower) sales volumes	2	(5)
	Lower realized prices (\$Cdn)	(7)	(20)
	Lower (higher) costs	5	(25)
change – electricity		-	(50)
<b>Other changes</b>			
	Higher gains on derivatives & foreign exchange	1	48
	Higher income taxes	(9)	(12)
	Cigar Lake remediation	6	10
	Miscellaneous	3	3
<b>Adjusted net earnings - 2011</b>		<b>104</b>	<b>259</b>

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

#### Average realized prices

		<b>Three months</b> <b>ended September 30</b>			<b>Nine months</b> <b>ended September 30</b>		
		<b>2011</b>	<b>2010</b>	<b>change</b>	<b>2011</b>	<b>2010</b>	<b>change</b>
Uranium	\$US/lb	<b>47.33</b>	40.63	16%	<b>47.06</b>	41.46	14%
	\$Cdn/lb	<b>45.97</b>	43.01	7%	<b>46.36</b>	43.90	6%
Fuel services	\$Cdn/kgU	<b>17.42</b>	16.32	7%	<b>18.05</b>	18.19	(1)%
Electricity	\$Cdn/MWh	<b>54.00</b>	57.00	(5)%	<b>54.00</b>	58.00	(7)%

## Quarterly trends

Highlights (\$ millions except per share amounts)	2011				2010				Canadian GAAP 2009
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	
Revenue	527	426	454	673	419	546	485	659	
Net earnings	39	55	92	205	98	70	143	598	
\$ per common share (basic)	0.10	0.14	0.23	0.52	0.25	0.18	0.36	1.52	
\$ per common share (diluted)	0.10	0.14	0.23	0.51	0.25	0.18	0.36	1.52	
Adjusted net earnings (non-IFRS/GAAP measures, see pages 10 & 11)	104	71	84	189	80	116	111	170	
\$ per share diluted	0.26	0.18	0.22	0.48	0.20	0.29	0.29	0.43	
Earnings from continuing operations	39	55	92	205	98	70	143	174	
\$ per common share (basic)	0.10	0.14	0.23	0.52	0.25	0.18	0.36	0.44	
\$ per common share (diluted)	0.10	0.14	0.23	0.51	0.25	0.18	0.36	0.44	
Cash provided by operations	190	20	267	109	(5)	271	146	188	

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

(\$ millions)	2011				2010				Canadian GAAP 2009
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	
Net earnings	39	55	92	205	98	70	143	598	
Adjustments (net of tax)									
Adjustments on derivatives	65	16	(8)	(16)	(18)	46	(32)	(4)	
Loss (earnings) from discontinued operations	-	-	-	-	-	-	-	(424)	
Adjusted net earnings (non-IFRS/GAAP measures, see pages 10 & 11)	104	71	84	189	80	116	111	170	

### Key things to note:

- Our financial results are strongly influenced by the performance of our uranium segment, which accounted for 63% of consolidated revenues in the third quarter of 2011.
- 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/GAAP 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 September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
Direct administration	37	34	9%	101	93	9%
Stock-based compensation	1	6	(83)%	5	7	(29)%
Total administration	38	40	(5)%	106	100	6%

Direct administration costs were \$37 million this quarter, or \$3 million higher than the same period last year. Through the first nine months of 2011, our direct administration costs were 9% higher than in 2010. These increases reflect the costs necessary for evaluating and pursuing growth opportunities including:

- increased hiring
- studies and analyses of various opportunities

## Exploration

Uranium exploration expenses were \$36 million this quarter, or \$1 million higher compared to the same quarter in 2010. Exploration expenses in the first nine months of the year increased to \$71 million from \$68 million in 2010. Exploration in 2011 is focused on Canada, Australia, Kazakhstan and the United States.

## Gains and losses on derivatives

We recorded \$76 million in losses on our derivatives this quarter, compared to gains of \$39 million in the third quarter of 2010. In the first nine months of the year, we recorded \$40 million in losses on our derivatives compared to gains of \$22 million in 2010. These losses reflect the weakening of the Canadian dollar in 2011.

## Income taxes

In the third quarter of 2011, we recorded an income tax recovery of \$22 million compared to \$1 million in the third quarter of 2010. The increase in recoveries was mainly due to higher losses being incurred in Canada compared to 2010, which was largely attributable to the losses we recorded on our derivatives. See note 12 to our interim financial statements for more detail.

On an adjusted basis, our income tax expense this quarter was \$2 million compared to a recovery of \$8 million in the third quarter of 2010. Our effective tax rate this quarter on an adjusted net earnings basis was 1% compared to a recovery of 11% for the third quarter of 2010.

In the first nine months of 2011, we recorded an income tax recovery of \$19 million compared to a recovery of \$3 million in 2010. The increase in recoveries was mainly due to higher losses being incurred in Canada compared to 2010, which was largely attributable to the losses we recorded on our derivatives. See note 12 to our interim financial statements for more detail.

On an adjusted basis, we recorded an income tax expense of \$8 million in the first nine months of 2011 compared to income tax recovery of \$4 million in 2010. Our effective tax rate for the first nine months of 2011, on an adjusted net earnings basis, reflects an expense of 3% compared to a recovery of 1% in 2010.

## Foreign exchange

At September 30, 2011:

- The value of the US dollar relative to the Canadian dollar was \$1.00 (US) for \$1.04 (Cdn), up from \$1.00 (US) for \$0.96 (Cdn) at June 30, 2011. The exchange rate averaged \$1.00 (US) for \$0.98 (Cdn) over the quarter.
- We had foreign currency contracts of \$1.4 billion (US) and EUR 46 million. The US currency contracts had an average exchange rate of \$1.00 (US) for \$1.00 (Cdn).

- The mark-to-market loss on all foreign exchange contracts was \$57 million compared to a \$37 million gain at June 30, 2011. We received cash of \$14 million this quarter and \$59 million for the first nine months of the year related to the settlement of foreign exchange contracts.

## Outlook for 2011

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 requirements over the next several years, 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 2011 reflects the expenditures necessary to help us achieve our strategy. Our outlook for uranium production, exploration, fuel services production, direct administration costs and capital expenditures has changed from the outlook included in our second quarter MD&A. We explain the changes below. All other items in the table are unchanged. We do not include an outlook for the items in the table that are marked with a dash.

See *Financial results by segment* for details.

	Consolidated	Uranium	Fuel services	Electricity
Production	-	21.7 million lbs	14 to 15 million kgU	-
Sales volume	-	31 to 33 million lbs	Increase 10% to 15%	-
Capacity factor	-	-	-	87%
Revenue compared to 2010	Increase 5% to 10%	Increase 10% to 15% <sup>1</sup>	Increase 5% to 10%	Decrease 10% to 15%
Unit cost of produced product sold (including DDR)	-	Increase 0% to 5% <sup>2</sup>	Increase 5% to 10%	Increase 10% to 15%
Direct administration costs compared to 2010 <sup>3</sup>	<b>Increase 10% to 15%</b>	-	-	-
Exploration costs compared to 2010	-	<b>Increase 0% to 5%</b>	-	-
Tax rate	Recovery of 0% to 5%	-	-	-
Capital expenditures	<b>\$575 million<sup>4</sup></b>	-	-	\$80 million

<sup>1</sup>Based on a uranium spot price of \$52.00 (US) per pound (the Ux spot price as of October 31, 2011), a long-term price indicator of \$63.00 (US) per pound (the Ux long-term indicator on October 31, 2011) and an exchange rate of \$1.00 (US) for \$1.00 (Cdn).

<sup>2</sup>This increase is based on the unit cost of sale for produced material. Any additional discretionary purchases in 2011 may cause the overall unit cost of product sold to increase further.

<sup>3</sup>Direct administration costs do not include stock-based compensation expenses.

<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. A delivery that was expected in the third quarter was moved into the fourth quarter. We now expect deliveries in the fourth quarter to account for over one-third of our 2011 sales volumes.

We now expect uranium production to be 21.7 million pounds this year compared to our previous forecast of 21.9 million pounds. The decrease is due to lower expected production at our US and Inkai operations, partially offset by higher expected production at McArthur River/Key Lake. Please see our *Uranium production outlook* for more information.

Exploration costs are now expected to increase 0% to 5% over 2010 (previously a 5% to 10% decrease) based on increased evaluation activities at Kintyre.

Due to current unfavourable market conditions for UF<sub>6</sub> conversion, we are reducing production for this year. We now expect fuel services to produce between 14 million and 15 million kgU this year (previously 15 million to 16 million kgU).

We have narrowed the scope of some of our business development activities and now expect our direct administration costs to increase 10% to 15% over 2010 (previously a 15% to 20% increase).

We expect capital expenditures to be about \$575 million in 2011 compared to our previous estimate of \$590 million due to changes in the scheduling of some projects. We do not expect this reduction in capital expenditures in 2011 will impact our plans to double annual uranium production to 40 million pounds by 2018.

### **Sensitivity analysis**

For the rest of 2011:

- a change of \$5 (US) per pound in both the Ux spot price (\$52.00 (US) per pound on October 31, 2011) and the Ux long-term price indicator (\$63.00 (US) per pound on October 31, 2011) would change revenue by \$13 million and net earnings by \$9 million
- a change of \$5/MWh in the electricity spot price would not change our 2011 net earnings as gains under BPLP's financial contracts have been fully locked in for 2011 and based on the assumption that the spot price will remain below the floor price of \$50.18/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 \$7 million and adjusted net earnings by \$3 million. This sensitivity is based on an exchange rate of \$1.00 (US) for \$1.00 (Cdn).

## **Liquidity and capital resources**

### **Cash from operations**

Cash from operations was \$195 million higher this quarter than in 2010 due largely to lower working capital requirements in 2011. Working capital changes were \$130 million less in 2011. In 2010, working capital required \$149 million in cash as a result of increases in accounts receivable and product inventories. Not including working capital requirements, our operating cash flows this quarter were higher by \$65 million, based on higher profits in the uranium business. See *Financial results by segment* for details.

Cash from operations was \$65 million higher for the first nine months of 2011 primarily due to a decrease in working capital requirements, partially offset by lower profits. Working capital changes were \$146 million less in 2011. In 2010, working capital changes required \$124 million due to decreases in accounts payable and increases in product inventories, partially offset by decreases in accounts receivable. Not including working capital requirements, our operating cash flows in the first nine months were down by \$81 million, as a result of lower profits in the uranium, fuel services, and electricity businesses. See *Financial results by segment* for details.

On transition to IFRS, we elected to classify interest payments as a financing activity rather than an operating activity in our statement of cash flows. This change will increase our reported cash flows from operating activities with a corresponding decrease in cash flows from financing activities. There is no net impact on consolidated cash flows as a result of this change in presentation. Prior period amounts have been recast to reflect this classification.

### **Debt**

We use debt to provide additional liquidity. We have sufficient borrowing capacity with unsecured lines of credit totalling about \$1.2 billion at September 30, 2011, the same as at June 30, 2011. At September 30, 2011, we had approximately \$606 million outstanding in letters of credit.

On November 1, 2011:

- we cancelled our \$100 million unsecured revolving credit facility that was maturing February 4, 2012
- we amended, and extended the term of our \$500 million unsecured revolving credit facility that was maturing November 30, 2012. This credit facility was increased to \$1.25 billion and now matures November 1, 2016. Each year on the anniversary date, and upon mutual agreement, the facility can be extended for an additional year. In addition to borrowing directly from this facility, we can use up to \$100 million of it to issue letters of credit and we may use it to provide liquidity for our commercial paper program, as necessary. From time to time we may increase the revolving credit facility above \$1.25 billion, by no less than increments of \$50 million, up to a total of \$1.75 billion. The facility ranks equally with all of our other senior debt. As of November 4, 2011, there was nothing outstanding under this facility.

With these changes, our unsecured lines of credit total about \$1.9 billion as of November 4, 2011.

### Debt covenants

As at September 30, 2011, we met the financial related covenants in our unsecured revolving credit facilities.

As noted under *Debt*, we cancelled one of our unsecured revolving credit facilities and amended and extended the other. We are bound by certain covenants in the remaining \$1.25 billion unsecured revolving credit facility. The financially related covenants place restrictions on total debt, including guarantees. As at November 4, 2011, we met these financial covenants and do not expect our operating and investment activities for the remainder of 2011 to be constrained by them.

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

We had two kinds of off-balance sheet arrangements at September 30, 2011:

- purchase commitments
- financial assurances

There have been no material changes to our long-term contractual obligations, purchase commitments and financial assurances since December 31, 2010, 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)	Sep 30, 2011	Dec 31, 2010	change
Cash and short-term investments	1,194	1,260	(5)%
Total debt	1,036	1,039	-
Other liabilities	667	459	45%
Inventory	690	533	29%

Total cash and short-term investments at September 30, 2011 were \$1,194 million, or 5% lower than at December 31, 2010, exceeding our total debt by \$158 million.

Total debt decreased by \$3 million to \$1,036 million at September 30, 2011. Of this total, \$105 million was classified as current, up \$6 million compared to December 31, 2010. See notes 10 and 11 of our audited annual financial statements for more detail.

Other liabilities increased by 45% to \$667 million at September 30, 2011. The increase was mainly the result of updating the actuarial valuation for our pension plans to reflect current market conditions.

Total product inventories increased by 29% to \$690 million. This was the result of higher uranium and fuel services inventories, as sales were lower than production and purchases in the first nine months of the year. In addition, the average carrying cost for uranium increased due to material purchased at near-market prices and higher costs for produced uranium.

## Financial results by segment

### Uranium

Highlights	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
Production volume (million lbs)	5.3	5.6	(5)%	15.8	16.5	(4)%
Sales volume (million lbs)	7.2	5.6	29%	19.1	20.5	(7)%
Average spot price (\$US/lb)	51.04	45.83	11%	57.89	43.01	35%
Average realized price (\$US/lb)	47.33	40.63	16%	47.06	41.46	14%
Average realized price (\$Cdn/lb)	45.97	43.01	7%	46.36	43.90	6%
Cost of sales (\$Cdn/lb) (including DDR)	27.59	23.61	17%	29.68	27.20	9%
Revenue (\$ millions)	332	240	38%	885	901	(2)%
Gross profit (\$ millions)	133	108	23%	319	343	(7)%
Gross profit (%)	40	45	(11)%	36	38	(5)%

#### Third quarter

Production volumes this quarter were 5% lower compared to the third quarter of 2010 primarily due to lower production from Smith Ranch-Highland and Inkai. See *Operating properties* for more information.

Uranium revenues this quarter were up 38% compared to 2010, due to a 29% increase in sales volumes and a 7% increase in the \$Cdn realized selling price.

Our realized prices this quarter were higher than the third quarter of 2010 mainly due to higher \$US prices under market-related contracts, partially offset by a less favourable exchange rate. In the third quarter of 2011, our realized foreign exchange rate was \$0.97 compared to \$1.06 in the prior year.

Total cash cost of sales (excluding DDR) increased by 68% (\$165 million compared to \$98 million in 2010). This was mainly the result of the following:

- the 29% increase in sales volumes
- average unit costs for produced uranium were 32% higher largely due to standby costs paid to AREVA relating to the McClean Lake mill. As well, royalty charges in 2011 were higher due to higher deliveries of produced material and higher realized prices.
- average unit costs for purchased uranium were 21% higher due to increased purchases at spot prices

The net effect was a \$25 million increase in gross profit for the quarter.

The following table shows our cash cost of sales per unit (excluding DDR) for produced and purchased material, including royalty charges on produced material, and the quantity of produced and purchased uranium sold.

Three months ended September 30	Unit cash cost of sale (\$Cdn/lb)			Quantity sold (million lbs)		
	2011	2010	change	2011	2010	change
Produced	23.63	17.85	32%	5.3	3.5	51%
Purchased	20.57	17.05	21%	1.9	2.1	(10)%
Total	22.84	17.55	30%	7.2	5.6	29%

## First nine months

Production volumes for the first nine months of the year were 4% lower than in the previous year mainly due to lower production from Smith Ranch-Highland and Inkai. See *Operating properties* for more information.

For the first nine months of 2011, uranium revenues were down 2% compared to 2010, due to a 7% decline in sales volumes partially offset by a 6% increase in the \$Cdn realized selling price.

Our realized prices were higher than the first nine months of 2010 mainly due to higher \$US prices under market-related contracts, partially offset by a less favourable exchange rate. In the first nine months of 2011, our realized foreign exchange rate was \$0.99 compared to \$1.06 in the prior year.

Total cash cost of sales (excluding DDR) increased by 6% (\$487 million compared to \$460 million in 2010). This was mainly the result of the following:

- average unit costs for produced uranium were 10% higher due to increased unit production costs relating to the lower production during the first nine months
- standby costs paid to AREVA relating to the McClean Lake mill
- average unit costs for purchased uranium were 22% higher due to increased purchases at spot prices

The net effect was a \$24 million decrease in gross profit for the first nine months.

The following table shows our cash cost of sales per unit (excluding DDR) for produced and purchased material, including royalty charges on produced material, and the quantity of produced and purchased uranium sold.

Nine months ended September 30	Unit cash cost of sale (\$Cdn/lb)			Quantity sold (million lbs)		
	2011	2010	change	2011	2010	change
Produced	24.78	22.54	10%	12.8	14.5	(12)%
Purchased	27.11	22.22	22%	6.3	6.0	5%
Total	25.54	22.45	14%	19.1	20.5	(7)%

## 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 the portfolio of long-term contracts we had in place on September 30, 2011 would respond to different spot prices. In other words, we would realize these prices only if the contract portfolio remained the same as it was on September 30, 2011, and none of the assumptions listed on the following page change.

*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
2011	46	47	49	51	53	55	57
2012	36	40	50	59	69	78	87
2013	43	46	54	63	72	81	88
2014	45	48	56	65	74	83	91
2015	43	47	56	66	77	87	97

\* The table with this heading which appeared on page 19 of our second quarter MD&A has been corrected. See *Note regarding our uranium price sensitivity analysis* on page 30 for more information.

The table illustrates the mix of long-term contracts in our September 30, 2011 portfolio, and is consistent with our contracting strategy. The table has been updated to September 30, 2011 to reflect:

- deliveries made and contracts entered into during the quarter
- changes to deliveries under some sales contracts to assist our customers who were directly impacted by the March nuclear incident in Japan
- changes to deliveries under some contracts where deliveries are tied to reactor requirements

These changes do not impact our outlook for 2011 sales.

Our portfolio includes a mix of fixed-price and market-price 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 2011 and 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 13% 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 3.5% per year for Canada and 2.5% per year for the United States and the United Kingdom (our prior inflation assumption was 2% per year)

## Fuel services

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

Highlights	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
Production volume (million kgU)	2.8	2.3	22%	11.6	11.7	(1)%
Sales volume (million kgU)	4.6	3.9	18%	11.1	10.7	4%
Realized price (\$Cdn/kgU)	17.42	16.32	7%	18.05	18.19	(1)%
Cost of sales (\$Cdn/kgU) (including DDR)	15.34	13.55	13%	15.42	13.38	15%
Revenue (\$ millions)	81	64	27%	199	195	2%
Gross profit (\$ millions)	10	11	(9)%	29	52	(44)%
Gross profit (%)	12	17	(29)%	15	27	(44)%

### Third quarter

Total revenue was \$17 million higher than in 2010 due to a 7% increase in the average realized price for our fuel services products along with an 18% increase in sales volumes.

Our \$Cdn realized price for fuel services was affected by a 5% increase in our realized price for UF<sub>6</sub> as well as the mix of products delivered in the quarter. In 2011, a higher proportion of fuel services sales were for fuel fabrication, which typically yields a much higher price than the other fuel services products.

The total cost of products and services sold (including DDR) increased by 34% (\$71 million compared to \$53 million in the third quarter of 2010) due to the increase in sales volumes along with the mix of products delivered in the quarter. As a result of the product mix, the average unit cost of sales was 13% higher for the quarter.

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

### First nine months

In the first nine months of the year, total revenue increased by 2% due to a 4% increase in sales volumes, partially offset by a 1% decline in the realized selling price.

The total cost of products and services sold (including DDR) increased by 18% (\$170 million compared to \$144 million in 2010) due to the increase in the unit cost of product sold. The average unit cost of sales was 15% higher due to the mix of products delivered in the year and the recognition of higher cost recoveries in 2010.

The net effect was a \$23 million decrease in gross profit.

## Electricity

### BPLP

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

Highlights (\$ millions except where indicated)	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
Output - terawatt hours (TWh)	6.7	6.3	6%	18.7	19.3	(3)%
Capacity factor (the amount of electricity the plants actually produced for sale as a percentage of the amount they were capable of producing)	93%	88%	6%	87%	90%	(3)%
Realized price (\$/MWh)	54	57	(5)%	54 <sup>1</sup>	58	(7)%
Average Ontario electricity spot price (\$/MWh)	33	43	(23)%	31	38	(18)%
Revenue	362	363	-	1,016	1,116	(9)%
Operating costs (net of cost recoveries)	232	229	1%	735	685	7%
Cash costs	182	184	(1)%	592	557	6%
Non-cash costs	50	45	11%	143	128	12%
Income before interest and finance charges	130	134	(3)%	281	431	(35)%
Interest and finance charges	14	16	(13)%	30	30	-
Cash from operations	137	131	5%	377	522	(28)%
Capital expenditures	61	25	144%	158	98	61%
Distributions	80	100	(20)%	205	405	(49)%
Operating costs (\$/MWh)	35	36	(3)%	39 <sup>1</sup>	35	11%

<sup>1</sup> Nine months ended September 30, 2011 are based on actual generation of 18.7 TWh plus deemed generation of 0.2 TWh

### Our earnings from BPLP

Highlights (\$ millions except where indicated)	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
BPLP's earnings before taxes (100%)	116	118	(2)%	251	401	(37)%
Cameco's share of pretax earnings before adjustments (31.6%)	37	37	-	79	127	(38)%
Proprietary adjustments	(2)	(1)	(100)%	(4)	(4)	-
Earnings before taxes from BPLP	35	36	(3)%	75	123	(39)%

### Third quarter

Total electricity revenue decreased slightly this quarter compared to the third quarter of 2010 due to lower realized prices which were almost completely offset by increased output. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$119 million this quarter under its agreement with the OPA, compared to \$41 million in the third quarter of 2010. About 53% of BPLP's output was sold under financial contracts this quarter, compared to 46% in the third quarter of 2010. Pricing under these contracts was lower than in 2010. From time to time BPLP enters the market to lock in the gains under these contracts.

The capacity factor was 93% this quarter, up from 88% in the third quarter of 2010 due to a lower volume of planned and unplanned outage days when compared to last year. Operating costs were similar at \$232 million compared to \$229 million in 2010.

The result was a 3% decrease in our share of earnings before taxes.

BPLP distributed \$80 million to the partners in the third quarter. Our share was \$25 million. The partners have agreed that BPLP will distribute excess cash monthly, and will make separate cash calls for major capital projects.

During the fourth quarter, there is a planned maintenance outage at one unit.

#### **First nine months**

Total electricity revenue for the first nine months decreased 9% compared to 2010 due to lower output and lower realized prices. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$351 million in the first nine months of 2011 under its agreement with the OPA, compared to \$224 million in the first nine months of 2010. The equivalent of about 49% of BPLP's output was sold under financial contracts in the first nine months of this year, compared to 41% in 2010. Pricing under these contracts was lower than in 2010. From time to time BPLP enters the market to lock in the gains under these contracts.

The capacity factor was 87% for the first nine months of this year, down from 90% in 2010 due to a higher volume of outage days during this year's planned outage compared to last year's planned outage. Operating costs were \$735 million compared to \$685 million in 2010 due to higher maintenance costs incurred during outage periods and increased staff costs.

The result was a 39% decrease in our share of earnings before taxes.

BPLP distributed \$205 million to the partners in the first nine months of 2011. Our share was \$65 million.

## Our operations and development projects

### Uranium – production overview

Production in our uranium segment this quarter was down 5% compared to the third quarter of 2010 mainly due to lower production from Smith Ranch-Highland and Inkai. In the first nine months of the year uranium production was down 4% compared to 2010. We have revised our production outlook down 1% for the year due to lower expected production at our US and Inkai operations, partially offset by higher expected production at McArthur River/Key Lake. See *Uranium 2011 Q3 updates* for more information.

#### Uranium production

Cameco's share (million lbs U <sub>3</sub> O <sub>8</sub> )	Three months ended September 30			Nine months ended September 30		
	2011	2010	change	2011	2010	change
McArthur River/Key Lake	3.8	3.7	3%	10.0	9.9	1%
Rabbit Lake	0.5	0.5	-	2.2	2.5	(12)%
Smith Ranch-Highland	0.3	0.4	(25)%	1.2	1.4	(14)%
Crow Butte	0.2	0.2	-	0.6	0.6	-
Inkai	0.5	0.8	(38)%	1.8	2.1	(14)%
Total	5.3	5.6	(5)%	15.8	16.5	(4)%

#### Outlook

We have geographically diverse sources of production. Our strategy is to double 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 2015*

Current forecast (million lbs U <sub>3</sub> O <sub>8</sub> )	2011	2012	2013	2014	2015
McArthur River/Key Lake	13.3	13.1	13.1	13.1	13.1
Rabbit Lake	3.6	3.6	3.6	3.6	3.6
US ISR	2.3	2.4	3.0	3.1	3.7
Inkai <sup>1</sup>	2.5	2.9	2.9	2.9	2.9
Cigar Lake	-	-	1.0	2.0	5.6
<b>Total share of production</b>	<b>21.7</b>	<b>22.0</b>	<b>23.6</b>	<b>24.7</b>	<b>28.9</b>
<b>Cameco's share of Inkai's production on which profits are generated<sup>2</sup></b>					
Inkai <sup>1</sup>	2.5	3.0	3.0	3.0	3.0
<b>Total<sup>2</sup></b>	<b>21.7</b>	<b>22.1</b>	<b>23.7</b>	<b>24.8</b>	<b>29.0</b>

<sup>1</sup> We have signed an MOA with Kazatomprom to increase annual production to 5.2 million pounds (100% basis). If implemented, the MOA will result in us receiving the right to purchase 2.9 million pounds of Inkai's annual production and receive profits on 3.0 million pounds. See page 26 for more information.

<sup>2</sup> We have adjusted the production table to reflect the share of Inkai's production on which our profits will be calculated under the MOA. See page 26 for more detail.

In 2013, production at McArthur River may be lower as we transition to mining upper zone 4.

Our 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

There is no certainty Inkai will receive these permits or approvals or we will reach a binding agreement with Kazatomprom. If Inkai does not receive the permits and approvals it needs, if they are delayed, or if we do not reach a binding agreement with Kazatomprom, Inkai may be unable to achieve its future annual production targets.

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This forecast is forward-looking information. It is based on the assumptions and subject to the material risks discussed on page 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 are available and function as designed, we have sufficient tailings capacity and our reserve estimates are accurate
- 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 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 government approvals
- 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 2011 Q3 updates

### Operating properties

#### McArthur River/Key Lake

##### Production update

At McArthur River/Key Lake, production was 3% higher in the third quarter and 1% higher for the first nine months of the year compared to the same periods last year. These increases were due to better recovery and improved equipment reliability at the mill. We expect the mill to operate through year end with no scheduled shutdown until 2012.

##### Operations update

At Key Lake, we continued work on the new oxygen, acid and steam plants. Commissioning of the steam plant commenced in the third quarter. We expect that the oxygen, acid and steam plants will all be operating by the end of the year.

#### 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 completed the scheduled mill maintenance shutdown this quarter, and the mill returned to normal operations on August 31, 2011. During the shutdown we completed the next phase of upgrades at the acid plant which included successful replacement of the acid plant final towers.

As announced on October 5, 2011, we signed a non-binding MOU with our Cigar Lake joint venture partners, which contemplates a change in the milling arrangements for the ore from Cigar Lake. See *Development project – Cigar Lake* for more information.

#### Smith Ranch-Highland and Crow Butte

##### Production update

Production this quarter was 17% lower and 10% lower for the first nine months of the year compared to the same periods last year due to lower production from Smith Ranch-Highland. We have decreased our production forecast for the year by 8% to 2.3 million pounds. The review process to obtain regulatory approvals has lengthened at Smith Ranch-Highland, which has increased the timeline to bring new wellfields into production.

##### Operations update

We continue to seek regulatory approvals to proceed with expansions at our various satellite operations in Wyoming and Nebraska. However, we are experiencing some permitting delays. As a result, we do not expect to receive approval to expand Reynolds Ranch this year. We recognize the regulators have a large volume of permits to process. We are working with them to improve communications and ensure we understand and meet their needs.

## Inkai

### Production update

Production for the quarter was 38% lower and 14% lower for the first nine months of the year compared to the same periods last year. For the quarter, lower production was primarily due to in-process uranium inventory changes. Prior to final commissioning of the processing facilities in 2010, the in-process uranium inventory had built up. A significant reduction of this inventory added to production in the third quarter of 2010 compared to 2011.

In addition, during 2010, the first year of full operation at Inkai, production benefited from the grade peak associated with multiple new wellfields. 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 are ramping up capacity at the Inkai operation in order to accommodate lower grades. We have lowered our production forecast to 2.5 million pounds, a 7% decrease from our initial estimate but in line with the currently approved production level.

### Operations update

Inkai's supply of sulphuric acid was consistent during the quarter. We experienced brief interruptions to supply during the first six months of the year. We do not anticipate any further interruptions to supply this year.

As announced on August 31, 2011, we signed an MOA with our partner, Kazatomprom, to increase production from blocks 1 and 2 to 5.2 million pounds of  $U_3O_8$  (100% basis). Under the MOA, our share of Inkai's annual production will be 2.9 million pounds with the processing plant at full capacity. We will also be entitled to receive profits on 3.0 million pounds.

We believe this is a fair and reasonable approach that allows both parties to benefit from changes in the uranium market that were not envisioned when the initial agreements were signed. To implement the increase, we need a binding agreement finalizing the terms of the MOA, government approval and an amendment to the resource use contract.

We continue to proceed with delineation drilling and the engineering of infrastructure and the test leach facility at block 3.

### Development project

#### Cigar Lake

The sinking of shaft 2 continues as planned. We expect to reach the main mine workings on the 480 metre level before the end of the year. The final depth of the shaft will be 500 metres.

We also continued drilling freeze holes from surface during the quarter.

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

As we noted under our Rabbit Lake update, we signed a non-binding MOU with our joint venture partners, which contemplates a change in the milling arrangements for the ore from Cigar Lake. Under the current toll milling agreements, both the McClean Lake mill and the Rabbit Lake mill would process uranium from Cigar Lake. Under the new arrangement, the McClean Lake mill would process and package all of the Cigar Lake uranium.

Rabbit Lake will continue to process ore mined on site and has the flexibility to process ore from other sources.

We expect the new milling arrangement will have a positive impact on the economics of the Cigar Lake project. To reflect the impact of this new milling arrangement and other developments (such as surface freezing) since the March 2010 Cigar Lake technical report, we are planning to file an updated Cigar Lake technical report with, or prior to, our February 2012 annual information form.

The most significant project developments since the March 2010 technical report are:

- a decrease in the estimated average cash operating cost to about \$18.60 per pound from \$23.14 per pound. The reduction in the operating cost estimate is primarily due to the new milling arrangement.
- a \$189 million increase in our share of the total capital cost at completion to \$1.1 billion. The capital cost estimate has increased primarily as a result of the implementation of the surface freeze strategy, general cost escalation, costs to upgrade and expand the McClean Lake mill and improvements to the mine plan.

The projected production startup date remains mid-2013.

Binding agreements with the owners of the Cigar Lake project and McClean Lake mill are required to proceed with the new milling arrangements. We expect these to be complete before November 30, 2011.

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

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The intention to mill all Cigar Lake ore at the McClean Lake mill and the expected benefit of that arrangement, the estimated average cash operating cost and our expected share of the total capital cost at completion for Cigar Lake, and our projected production startup date of mid-2013 are forward-looking information. They are based on the assumptions and subject to the material risks discussed on page 3, and specifically on the assumptions and risks listed here.

#### *Assumptions*

- we will reach binding agreements to implement the MOU
- our expectation that the arrangement will result in the expected reduction in the operating cost
- our Cigar Lake remediation, development and production plans succeed
- there is no material delay or disruption in our plans as a result of additional water inflows, natural phenomena, equipment failure or other causes

#### *Material Risks*

- we are unable to reach binding agreements to implement the new milling arrangements on expected terms
- the new milling arrangement does not result in the expected cost savings or other benefits
- our remediation, development or production plans for Cigar Lake are delayed or do not succeed for any reason

### **Projects under evaluation**

In August, we hosted a group of Martu from Australia at our Saskatchewan mine sites. The experience was positive and we continue to work with the Martu to complete a memorandum of understanding for a mine development agreement at Kintyre.

We continue to work on the pre-feasibility study at Kintyre. We initially planned to complete the pre-feasibility study by the end of 2011. However, limited access to the site due to weather and changes in the scope of the study, including additional drilling and a comprehensive review of processing options, have delayed completion. We now expect to complete the pre-feasibility study by mid-2012.

We continue to advance the Kintyre and Millennium projects toward development decisions using our stage gate process. See our annual MD&A for more information regarding these projects.

## Fuel services 2011 Q3 updates

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

### Production update

Fuel services production totalled 2.8 million kgU this quarter, compared to 2.3 million kgU in the third quarter of 2010. Production was 22% higher due to the planned maintenance shutdown of the Port Hope UF<sub>6</sub> plant in 2010.

Production for the first nine months of the year was 11.6 million kgU compared to 11.7 million kgU in the first nine months of 2010.

Due to current unfavourable market conditions for UF<sub>6</sub> conversion, we are reducing production for this year. We now expect fuel services to produce between 14 million and 15 million kgU this year (previously 15 million to 16 million kgU).

Based on the unfavourable market outlook for UF<sub>6</sub> conversion, we have discontinued discussions to extend our toll conversion contract with SFL beyond 2016. We remain fully committed to the current contract. Should market conditions improve over the next few years, we would consider resuming our discussions to extend the contract.

## 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 nine months of 2011, we paid PACL \$46.9 million for construction and contracting services (2010 - \$19.0 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 2010 annual MD&A, we have identified the critical accounting estimates that reflect the more significant judgments used in the preparation of our financial statements. These estimates have not changed as a result of our adoption of IFRS. 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 September 30, 2011, 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 September 30, 2011, 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 September 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## New accounting pronouncements

### Financial instruments

In October 2010, the International Accounting Standards Board (“IASB”) issued IFRS 9, *Financial Instruments* (“IFRS 9”). This standard is effective for periods beginning on or after January 1, 2013 and is part of a wider project to replace IAS 39, *Financial Instruments: Recognition and Measurement*. 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. We are assessing the impact of this new standard on our financial statements.

### Consolidated financial statements

In May 2011, the IASB issued IFRS 10, *Consolidated Financial Statements* (“IFRS 10”). This standard is effective for periods beginning on or after January 1, 2013 and 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. We are assessing the impact of this new standard on our financial statements.

### Joint arrangements

In May 2011, the IASB issued IFRS 11, *Joint Arrangements* (“IFRS 11”). This standard is effective for periods beginning on or after January 1, 2013 and 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. We are assessing the impact of this new standard on our financial statements.

### Disclosure of interests in other entities

In May 2011, the IASB issued IFRS 12, *Disclosure of Interests in Other Entities* (“IFRS 12”). This standard is effective for periods beginning on or after January 1, 2013 and 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. We are assessing the impact of this new standard on our financial statements.

### Fair value measurement

In May 2011, the IASB issued IFRS 13, *Fair Value Measurement* ("IFRS 13"). This standard is effective for periods beginning on or after January 1, 2013 and 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. We are assessing the impact of this new standard on our financial statements.

### Employee benefits

In June 2011, the IASB issued an amended version of IAS 19, *Employee Benefits* ("IAS 19"). This amendment is effective for periods beginning on or after January 1, 2013 and 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. We are assessing the impact of this revised standard on our financial statements.

### 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 periods beginning on or after January 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. We are assessing the impact of this revised standard on our financial statements.

### International financial reporting standards (IFRS)

Our three-phase implementation plan, described in our annual MD&A, is substantially complete. Effective January 1, 2011, we adopted IFRS for Canadian publicly accountable enterprises. Our interim financial statements for the third quarter of 2011 have been prepared in accordance IFRS including comparative amounts for 2010. Details of the accounting differences can be found in note 3 to our interim financial statements.

### Note regarding our uranium price sensitivity analysis

The table appearing on page 19 of our second quarter MD&A titled *Expected realized uranium price sensitivity under various spot price assumptions* was intended to indicate how the portfolio of long-term contracts we had in place on June 30, 2011 would respond to different spot prices and other stated assumptions. That table should have appeared as follows:

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

<b>(\$US/lb U<sub>3</sub>O<sub>8</sub>)</b>							
<b>Spot prices</b>	<b>\$20</b>	<b>\$40</b>	<b>\$60</b>	<b>\$80</b>	<b>\$100</b>	<b>\$120</b>	<b>\$140</b>
2011	43	45	49	53	57	61	65
2012	35	40	49	57	66	75	83
2013	42	45	54	62	72	80	88
2014	45	48	56	65	74	83	91
2015	42	46	56	66	76	87	96

Although this table is now replaced by the more current table which appears on page 18 under the heading *Price sensitivity analysis: uranium*, we are providing the corrected version of the table published in our second quarter MD&A to facilitate comparison with the current table.

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

(Unaudited)

(\$Cdn Thousands, except per share amounts)

	Note	Three Months Ended Sep 30/11	Sep 30/10	Nine Months Ended Sep 30/11	Sep 30/10
Revenue from products and services		\$526,952	\$419,475	\$1,406,917	\$1,450,245
Cost of products and services sold		284,519	203,239	821,301	758,302
Depreciation, depletion and amortization		63,420	60,389	162,291	172,641
<b>Cost of sales</b>		<b>347,939</b>	263,628	<b>983,592</b>	930,943
<b>Gross profit</b>		<b>179,013</b>	155,847	<b>423,325</b>	519,302
Administration		38,089	40,122	106,056	100,011
Exploration		35,619	35,430	70,577	68,340
Research and development		2,071	1,033	3,797	2,654
Cigar Lake remediation		576	6,622	4,113	14,460
Loss (gain) on sale of assets		418	(481)	1,113	(297)
<b>Earnings from operations</b>		<b>102,240</b>	73,121	<b>237,669</b>	334,134
Finance costs	11	(16,385)	(22,808)	(55,946)	(66,443)
Gains (losses) on derivatives	16	(75,804)	39,119	(40,216)	22,049
Finance income		5,922	5,416	19,037	13,587
Share of loss from equity-accounted investees		(1,443)	(1,624)	(5,573)	(4,397)
Other income (expense)		(1,036)	(408)	3,053	2,159
<b>Earnings before income taxes</b>		<b>13,494</b>	92,816	<b>158,024</b>	301,089
Income tax recovery	12	(21,711)	(1,045)	(18,777)	(3,126)
<b>Net earnings</b>		<b>\$35,205</b>	<b>\$93,861</b>	<b>\$176,801</b>	<b>\$304,215</b>
<b>Net earnings (loss) attributable to:</b>					
Equity holders		\$39,452	\$97,513	\$185,590	\$310,850
Non-controlling interest		(4,247)	(3,652)	(8,789)	(6,635)
<b>Net earnings</b>		<b>\$35,205</b>	<b>\$93,861</b>	<b>\$176,801</b>	<b>\$304,215</b>
<b>Earnings per common share attributable to equity holders</b>					
Basic	17	\$0.10	\$0.25	\$0.47	\$0.79
Diluted	17	\$0.10	\$0.25	\$0.47	\$0.79

See accompanying notes to condensed consolidated interim financial statements.

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

	Note	Three Months Ended		Nine Months Ended	
		Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
<b>Net earnings</b>		<b>\$35,205</b>	<b>\$93,861</b>	<b>\$176,801</b>	<b>\$304,215</b>
Other comprehensive income (loss), net of taxes	12				
Exchange differences on translation of foreign operations		51,339	30,572	39,900	22,150
Gains on derivatives designated as cash flow hedges		544	1,826	3,666	12,130
Gains on derivatives designated as cash flow hedges transferred to net earnings		(4,062)	(14,760)	(15,294)	(51,278)
Unrealized gains on available-for-sale securities		60	139	744	1,072
Losses (gains) on available-for-sale securities transferred to net earnings		(8)	15	(1,848)	(2,614)
Defined benefit plan actuarial losses	7	(109,897)	(167,536)	(109,897)	(167,536)
Other comprehensive loss, net of taxes		<b>(62,024)</b>	<b>(149,744)</b>	<b>(82,729)</b>	<b>(186,076)</b>
<b>Total comprehensive income (loss)</b>		<b>(\$26,819)</b>	<b>(\$55,883)</b>	<b>\$94,072</b>	<b>\$118,139</b>
<b>Other comprehensive income (loss) attributable to:</b>					
Equity holders		\$ (58,411)	\$ (166,447)	\$ (81,757)	\$ (195,647)
Non-controlling interest		(3,613)	16,703	(972)	9,571
<b>Other comprehensive loss for the period</b>		<b>\$(62,024)</b>	<b>\$(149,744)</b>	<b>\$(82,729)</b>	<b>\$(186,076)</b>
<b>Total comprehensive income (loss) attributable to:</b>					
Equity holders		\$ (18,959)	\$ (68,934)	\$ 103,833	\$ 115,203
Non-controlling interest		(7,860)	13,051	(9,761)	2,936
<b>Total comprehensive income (loss) for the period</b>		<b>(\$26,819)</b>	<b>(\$55,883)</b>	<b>\$94,072</b>	<b>\$118,139</b>

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Financial Position**  
(Unaudited)  
(\$Cdn Thousands)

	Note	As At	
		Sep 30/11	Dec 31/10
<b>Assets</b>			
Current assets			
Cash and cash equivalents		\$542,771	\$376,621
Short-term investments		651,177	883,032
Accounts receivable		286,547	448,479
Current tax assets		37,172	42,190
Inventories	5	689,852	533,090
Supplies and prepaid expenses		202,802	190,079
Current portion of long-term receivables and other	6	39,190	91,447
<b>Total current assets</b>		<b>2,449,511</b>	<b>2,564,938</b>
Property, plant and equipment			
Intangible assets		4,221,914	3,954,647
Long-term receivables, investments and other	6	100,582	94,270
Investments in equity-accounted investees		309,449	342,675
Deferred tax assets		216,809	220,430
		78,944	25,594
<b>Total non-current assets</b>		<b>4,927,698</b>	<b>4,637,616</b>
<b>Total assets</b>		<b>\$7,377,209</b>	<b>\$7,202,554</b>
<b>Liabilities and Shareholders' Equity</b>			
Current liabilities			
Accounts payable and accrued liabilities		\$359,189	\$362,467
Current tax liabilities		19,831	35,042
Short-term debt		91,049	85,588
Dividends payable		39,471	27,605
Current portion of finance lease obligation		14,410	13,177
Current portion of other liabilities	7	129,999	53,192
Current portion of provisions		17,280	19,394
<b>Total current liabilities</b>		<b>671,229</b>	<b>596,465</b>
Long-term debt			
Finance lease obligation		796,223	794,483
Other liabilities	7	134,806	145,834
Provisions		536,997	405,477
Deferred tax liabilities		368,122	365,573
		-	26,270
<b>Total non-current liabilities</b>		<b>1,836,148</b>	<b>1,737,637</b>
Shareholders' equity			
Share capital		1,841,839	1,833,257
Contributed surplus		150,892	142,376
Retained earnings		2,643,773	2,690,184
Other components of equity		52,636	24,496
<b>Total shareholders' equity attributable to equity holders</b>		<b>4,689,140</b>	<b>4,690,313</b>
Non-controlling interest			
		180,692	178,139
<b>Total shareholders' equity</b>		<b>4,869,832</b>	<b>4,868,452</b>
<b>Total liabilities and shareholders' equity</b>		<b>\$7,377,209</b>	<b>\$7,202,554</b>

Commitments and contingencies [notes 12,15]

See accompanying notes to condensed consolidated interim financial statements.

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

	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, 2011	\$1,833,257	\$142,376	\$2,690,184	\$(7,603)	\$30,306	\$1,793	\$4,690,313	\$178,139	\$4,868,452
Net earnings	-	-	185,590	-	-	-	185,590	(8,789)	176,801
Total other comprehensive income	-	-	(109,897)	40,872	(11,628)	(1,104)	(81,757)	(972)	(82,729)
<b>Total comprehensive income for the period</b>	-	-	75,693	40,872	(11,628)	(1,104)	103,833	(9,761)	94,072
Stock-based compensation	-	14,520	-	-	-	-	14,520	-	14,520
Share options exercised	8,582	(6,004)	-	-	-	-	2,578	-	2,578
Dividends	-	-	(118,413)	-	-	-	(118,413)	-	(118,413)
Change in ownership interests in subsidiaries	-	-	(3,691)	-	-	-	(3,691)	3,883	192
Transactions with owners - contributed equity	-	-	-	-	-	-	-	8,431	8,431
<b>Balance at September 30, 2011</b>	<b>\$1,841,839</b>	<b>\$150,892</b>	<b>\$2,643,773</b>	<b>\$33,269</b>	<b>\$18,678</b>	<b>\$689</b>	<b>\$4,689,140</b>	<b>\$180,692</b>	<b>\$4,869,832</b>
Balance at January 1, 2010	1,809,861	131,577	2,392,940	-	89,457	2,225	4,426,060	164,040	4,590,100
Net earnings	-	-	310,850	-	-	-	310,850	(6,635)	304,215
Total other comprehensive income	-	-	(167,536)	12,579	(39,148)	(1,542)	(195,647)	9,571	(186,076)
<b>Total comprehensive income for the period</b>	-	-	143,314	12,579	(39,148)	(1,542)	115,203	2,936	118,139
Stock-based compensation	-	7,645	-	-	-	-	7,645	-	7,645
Share options exercised	6,333	(1,067)	-	-	-	-	5,266	-	5,266
Dividends	-	-	(82,561)	-	-	-	(82,561)	-	(82,561)
Transactions with owners - contributed equity	-	-	-	-	-	-	-	7,156	7,156
<b>Balance at September 30, 2010</b>	<b>\$1,816,194</b>	<b>\$138,155</b>	<b>\$2,453,693</b>	<b>\$12,579</b>	<b>\$50,309</b>	<b>\$683</b>	<b>\$4,471,613</b>	<b>\$174,132</b>	<b>\$4,645,745</b>

See accompanying notes to condensed consolidated interim financial statements.

## Consolidated Statements of Cash Flows

(Unaudited)  
(\$Cdn Thousands)

	Note	Three Months Ended		Nine Months Ended	
		Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
<b>Operating activities</b>					
Net earnings		\$35,205	\$93,861	\$176,801	\$304,215
Adjustments for:					
Depreciation, depletion and amortization		63,420	60,389	162,291	172,641
Deferred charges		(927)	(6,534)	(9,113)	(24,436)
Unrealized losses (gains) on derivatives		91,363	(31,552)	101,219	64,640
Share-based compensation	14	3,200	1,323	14,520	7,645
Loss (gain) on sale of assets		418	(481)	1,113	(297)
Finance costs	11	16,385	22,808	55,946	66,443
Finance income		(5,922)	(5,416)	(19,037)	(13,587)
Share of loss from equity-accounted investees		1,443	1,624	5,573	4,397
Other expense (income)		1,036	408	(3,053)	(2,159)
Income tax recovery	12	(21,711)	(1,045)	(18,777)	(3,126)
Interest received		6,658	2,767	16,347	7,387
Income taxes paid		(6,101)	(841)	(54,129)	(57,828)
Income taxes refunded		24,706	7,326	24,706	10,245
Other operating items	13	(19,512)	(149,140)	22,462	(123,899)
<b>Net cash provided by (used in) operations</b>		<b>189,661</b>	<b>(4,503)</b>	<b>476,869</b>	<b>412,281</b>
<b>Investing activities</b>					
Additions to property, plant and equipment		(179,465)	(109,233)	(443,342)	(303,595)
Change in short-term investments		222,075	53,759	232,821	(714,271)
Decrease (increase) in long-term receivables, investments and other		11,882	(3,079)	39,376	(15,312)
Proceeds from sale of property, plant and equipment		29	481	61	5,946
<b>Net cash provided by (used in) investing</b>		<b>54,521</b>	<b>(58,072)</b>	<b>(171,084)</b>	<b>(1,027,232)</b>
<b>Financing activities</b>					
Increase in debt		7,883	-	3,459	-
Decrease in debt		(3,350)	(1,674)	(9,796)	(11,186)
Interest paid		(24,064)	(24,322)	(51,152)	(51,835)
Contributions from non-controlling interest		3,154	3,008	9,605	7,646
Proceeds from issuance of shares, stock option plan		58	2,999	6,996	5,266
Dividends paid		(39,472)	(27,512)	(106,547)	(78,590)
<b>Net cash used in financing</b>		<b>(55,791)</b>	<b>(47,501)</b>	<b>(147,435)</b>	<b>(128,699)</b>
Increase (decrease) in cash during the period		188,391	(110,076)	158,350	(743,650)
Exchange rate changes on foreign currency cash balances		8,249	(1,327)	7,800	(3,942)
Cash and cash equivalents at beginning of period		346,131	465,040	376,621	1,101,229
<b>Cash and cash equivalents at end of period</b>		<b>\$542,771</b>	<b>\$353,637</b>	<b>\$542,771</b>	<b>\$353,637</b>
<b>Cash and cash equivalents is comprised of:</b>					
Cash				\$59,521	\$68,798
Cash equivalents				483,250	284,839
				\$542,771	\$353,637

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 September 30, 2011 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*. These condensed consolidated interim financial statements are for part of the period covered by the first annual financial statements prepared under International Financial Reporting Standards (“IFRS”) and IFRS 1, *First-time Adoption of International Financial Reporting Standards* (“IFRS 1”), has been applied. The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements. These condensed consolidated interim financial statements have been prepared in accordance with the accounting policies the Company expects to adopt in its December 31, 2011 financial statements. Those accounting policies are based on the IFRS and IFRS Interpretations Committee (“IFRIC”) interpretations that the Company expects to be applicable at that time.

The Company’s consolidated financial statements for the year ended December 31, 2010 were previously prepared in accordance with Canadian generally accepted accounting principles (“GAAP”). Accordingly, the comparative figures for 2010 were recast and an explanation of how the transition from Canadian GAAP to IFRS has affected the financial statements of the Company is provided in note 3. Certain disclosures in addition to the minimum disclosure requirements under IAS 34 were added in order to highlight the changes from the Company’s 2010 annual consolidated financial statements prepared in accordance with Canadian GAAP. In 2012 and beyond, the Company may not provide the same amount of disclosure in the condensed consolidated interim financial statements as the reader will be able to rely on the annual consolidated financial statements which will be prepared in accordance with IFRS.

These condensed consolidated interim financial statements were authorized for issuance by the Company’s Board of Directors on November 4, 2011.

##### **(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 are measured at fair value, available-for-sale financial assets are measured at fair value, liabilities for cash-settled share-based payment arrangements are measured at fair value and the defined benefit asset is recognized as the net total of the plan assets.

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 judgements made by management in applying the Company’s accounting policies and key sources of estimation uncertainty are expected to be the same as those to be applied in the first annual IFRS financial statements.

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 March 31, 2011 condensed consolidated interim financial statements.

Since the Company's consolidated financial statements for the year ended December 31, 2010 were previously prepared in accordance with GAAP, a summary of significant accounting policies was disclosed in note 2 of the March 31, 2011 condensed consolidated interim financial statements. The summary of accounting policies is a description of the accounting methods and practices that have been used in the preparation of these condensed consolidated interim financial statements and is presented to assist the reader in interpreting the statements contained herein. These accounting policies have been applied consistently to all entities within the consolidated group and to all periods presented in these condensed consolidated interim financial statements.

### 3. Explanation of Transition to IFRS

As stated in note 2(a), these condensed consolidated interim financial statements have been prepared in accordance with IFRS. The accounting policies set out in note 2 of the March 31, 2011 condensed consolidated interim financial statements have been applied for all periods presented in the condensed consolidated interim financial statements for the period ended September 30, 2011.

In preparing its opening IFRS statement of financial position, the Company has adjusted amounts previously reported in financial statements prepared in accordance with Canadian GAAP. An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's financial statements is set out in the following tables and the notes that accompany the tables.

#### **Elected IFRS 1 exemptions applicable to the presentation of the internal opening IFRS financial position**

Cameco has elected and applied the following IFRS 1 exemptions:

- (i) Borrowing costs** – IFRS 1 provides the option to apply IAS 23, *Borrowing Costs* (“IAS 23”), prospectively from the transition date to IFRS (January 1, 2010), or from a particular pre-transition date elected by the first time adopter. Borrowing costs may be capitalized on qualifying assets for which the commencement date for capitalization was on or after the date selected. The Company elected to apply IAS 23 prospectively from the date of transition to IFRS. Based on this election, Cameco expensed the borrowing costs capitalized before January 1, 2010 under Canadian GAAP and will capitalize borrowing costs incurred on qualifying assets for which the commencement date for capitalization is subsequent to January 1, 2010.
- (ii) Decommissioning liabilities** – The application of IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities* (“IFRIC 1”), would require the Company to recalculate, retrospectively, the effect of each change in its reclamation provision prior to the date of transition, along with the impact on the related assets and depreciation. IFRS 1 provides the option to instead measure the liability and related depreciation effects as at the date of transition to IFRS. Cameco has elected to apply this exemption and calculated the impact on the statement of financial position as of January 1, 2010.
- (iii) Employee benefits** – IAS 19, *Employee Benefits* (“IAS 19”), requires extensive disclosures in respect of defined benefit plans. IFRS 1 provides an optional exemption that permits the first-time adopter to elect to provide these disclosures prospectively from the date of transition. The Company has elected to apply this exemption and will provide the full disclosures required by IAS 19 in its first annual consolidated financial statements prepared under IFRS.
- (iv) Share-based compensation** – IFRS 2, *Share-Based Payments* (“IFRS 2”), encourages application of its provisions to liabilities arising from cash-settled transactions that were settled before the transition date but only requires application to those transactions that will be settled after the transition date. The Company elected to apply IFRS 2 only to liabilities arising from share-based compensation transactions that existed at January 1, 2010.
- (v) Business combinations** – The application of IFRS 3, *Business Combinations* (“IFRS 3”), requires the restatement of all past business combinations in accordance with IFRS 3. IFRS 1 provides the option to apply IFRS 3 prospectively from the transition date, or from a particular pre-transition date elected by the Company. The Company elected to not restate any past business combinations and to apply IFRS 3 prospectively from the transition date.
- (vi) Cumulative translation differences** – IAS 21, *The Effects of Changes in Foreign Exchange Rates*, would require the Company to calculate currency translation differences retrospectively, from the date a subsidiary or associate was formed or acquired. IFRS 1 provides the option of resetting cumulative translations gains and losses to zero at the transition date. The Company elected to reset cumulative translations losses to zero through opening retained earnings at the transition date.

## Reconciliation of Equity at September 30, 2010

	Cdn GAAP	Sep 30, 2010 effect of transition	IFRS
<b>Assets</b>			
Current assets			
Cash and cash equivalents	\$353,637	\$ -	\$353,637
Short-term investments	916,787	-	916,787
Accounts receivable (a)	357,570	727	358,297
Inventories (b),(d)	514,230	(9,957)	504,273
Supplies and prepaid expenses (a)	171,249	1,043	172,292
Current portion of long-term receivables and other	86,492	-	86,492
<b>Total current assets</b>	<b>2,399,965</b>	<b>(8,187)</b>	<b>2,391,778</b>
Property, plant and equipment (a),(c),(d),(e),(k)	4,245,743	(383,299)	3,862,444
Intangible assets	95,218	-	95,218
Long-term receivables, investments, other (a),(f),(g)	670,399	(282,651)	387,748
Investments in equity-accounted investees (f),(h)	-	222,139	222,139
Deferred tax assets (p),(q),(r)	34,801	44,175	78,976
<b>Total non-current assets</b>	<b>5,046,161</b>	<b>(399,636)</b>	<b>4,646,525</b>
<b>Total assets</b>	<b>\$7,446,126</b>	<b>\$(407,823)</b>	<b>\$7,038,303</b>
<b>Liabilities and Shareholders' Equity</b>			
Current liabilities			
Accounts payable and accrued liabilities (a),(i)	\$351,496	\$(22,695)	\$328,801
Current tax liabilities	30,765	786	31,551
Short-term debt	83,746	-	83,746
Dividends payable	27,542	-	27,542
Current portion of finance lease obligation	12,766	-	12,766
Current portion of other liabilities (a)	46,730	23,479	70,209
Current portion of provisions (a),(b),(j),(k),(l)	-	16,859	16,859
Deferred tax liabilities (p),(q),(r)	35,418	(35,418)	-
<b>Total current liabilities</b>	<b>588,463</b>	<b>(16,989)</b>	<b>571,474</b>
Long-term debt	791,001	-	791,001
Finance lease obligation	152,533	-	152,533
Provision for reclamation (j)	261,686	(261,686)	-
Other liabilities (a),(g),(j)	251,822	247,656	499,478
Provisions (a),(b),(j),(k),(l)	-	339,053	339,053
Deferred tax liabilities (p),(q),(r)	172,000	(132,981)	39,019
<b>Total non-current liabilities</b>	<b>1,629,042</b>	<b>192,042</b>	<b>1,821,084</b>
Minority interest (o)	174,132	(174,132)	-
Shareholders' equity			
Share capital (m)	1,518,794	297,400	1,816,194
Contributed surplus	138,155	-	138,155
Retained earnings (s)	3,384,154	(930,461)	2,453,693
Other components of equity (b),(d),(g),(h),(k),(n),(p),(r)	13,386	50,185	63,571
<b>Total shareholders' equity attributable to equity holders</b>	<b>5,054,489</b>	<b>(582,876)</b>	<b>4,471,613</b>
Non-controlling interest (o)	-	174,132	174,132
<b>Total shareholders' equity</b>	<b>5,054,489</b>	<b>(408,744)</b>	<b>4,645,745</b>
<b>Total liabilities and shareholders' equity</b>	<b>\$7,446,126</b>	<b>\$(407,823)</b>	<b>\$7,038,303</b>

## Reconciliation of Total Comprehensive Income for 2010

	Three Months Ended September 30, 2010			Nine Months Ended September 30, 2010		
	Cdn GAAP	effect of transition	IFRS	Cdn GAAP	effect of transition	IFRS
Revenue from products and services	\$419,475	\$ -	\$419,475	\$1,450,245	\$ -	\$1,450,245
Products and services sold (a),(l)	203,857	(618)	203,239	770,600	(12,298)	758,302
Depreciation, depletion and amortization (a),(b),(c),(d),(e),(k)	63,338	(2,949)	60,389	180,869	(8,228)	172,641
<b>Cost of sales</b>	<b>267,195</b>	<b>(3,567)</b>	<b>263,628</b>	<b>951,469</b>	<b>(20,526)</b>	<b>930,943</b>
<b>Gross profit</b>	<b>152,280</b>	<b>3,567</b>	<b>155,847</b>	<b>498,776</b>	<b>20,526</b>	<b>519,302</b>
Administration (g),(i)	40,205	(83)	40,122	101,258	(1,247)	100,011
Exploration	35,430	-	35,430	68,340	-	68,340
Research and development	1,033	-	1,033	2,654	-	2,654
Cigar Lake remediation	6,622	-	6,622	14,460	-	14,460
Gain on sale of assets	(481)	-	(481)	(297)	-	(297)
<b>Earnings from operations</b>	<b>69,471</b>	<b>3,650</b>	<b>73,121</b>	<b>312,361</b>	<b>21,773</b>	<b>334,134</b>
Finance costs (b),(c),(l)	(7,310)	(15,498)	(22,808)	(20,890)	(45,553)	(66,443)
Gains on derivatives	39,099	20	39,119	22,049	-	22,049
Finance income	5,416	-	5,416	13,587	-	13,587
Share of loss from equity-accounted investees (h)	(4,483)	2,859	(1,624)	(12,954)	8,557	(4,397)
Other income (expense)	(408)	-	(408)	2,159	-	2,159
<b>Earnings before income taxes</b>	<b>101,785</b>	<b>(8,969)</b>	<b>92,816</b>	<b>316,312</b>	<b>(15,223)</b>	<b>301,089</b>
Income tax expense (recovery) (p),(q),(r)	7,824	(8,869)	(1,045)	14,738	(17,864)	(3,126)
<b>Net earnings</b>	<b>\$93,961</b>	<b>\$(100)</b>	<b>\$93,861</b>	<b>\$301,574</b>	<b>\$2,641</b>	<b>\$304,215</b>
<b>Net earnings (loss) attributable to:</b>						
Equity holders	\$97,613	\$(100)	\$97,513	\$308,209	\$2,641	\$310,850
Non-controlling interest	(3,652)	-	(3,652)	(6,635)	-	(6,635)
<b>Net earnings</b>	<b>\$93,961</b>	<b>\$(100)</b>	<b>\$93,861</b>	<b>\$301,574</b>	<b>\$2,641</b>	<b>\$304,215</b>
<b>Basic earnings per common share</b>	<b>\$0.25</b>	<b>\$ -</b>	<b>\$0.25</b>	<b>\$0.78</b>	<b>\$ -</b>	<b>\$0.79</b>
<b>Diluted earnings per common share</b>	<b>\$0.25</b>	<b>\$ -</b>	<b>\$0.25</b>	<b>\$0.78</b>	<b>\$ -</b>	<b>\$0.79</b>
<b>Net earnings</b>	<b>\$93,961</b>	<b>\$(100)</b>	<b>\$93,861</b>	<b>\$301,574</b>	<b>\$2,641</b>	<b>\$304,215</b>
Other comprehensive income (loss), net of taxes						
Exchange differences on translation of foreign currency operations	31,078	(506)	30,572	22,363	(213)	22,150
Gains (losses) on derivatives designated as cash flow hedges	1,826	-	1,826	12,130	-	12,130
Gains on derivatives designated as cash flow hedges transferred to net earnings	(14,760)	-	(14,760)	(51,278)	-	(51,278)
Unrealized gains on available-for-sale securities	139	-	139	1,072	-	1,072
Gains on available-for-sale securities transferred to net earnings	15	-	15	(2,614)	-	(2,614)
Defined benefit plan actuarial losses (a),(g),(p)	-	(167,536)	(167,536)	-	(167,536)	(167,536)
Other comprehensive income (loss), net of taxes	18,298	(168,042)	(149,744)	(18,327)	(167,749)	(186,076)
<b>Total comprehensive income (loss), net of taxes</b>	<b>\$112,259</b>	<b>\$(168,142)</b>	<b>\$(55,883)</b>	<b>\$283,247</b>	<b>\$(165,108)</b>	<b>\$118,139</b>
<b>Total comprehensive income (loss) attributable to:</b>						
Equity holders	\$99,208	\$(168,142)	\$(68,934)	\$280,311	\$(165,108)	\$115,203
Non-controlling interest	13,051	-	13,051	2,936	-	2,936
<b>Total comprehensive income</b>	<b>\$112,259</b>	<b>\$(168,142)</b>	<b>\$(55,883)</b>	<b>\$283,247</b>	<b>\$(165,108)</b>	<b>\$118,139</b>

## Notes to the reconciliations

The impact on deferred tax of the adjustments described below is set out in note (p).

- a) As a result of BPLP also transitioning to IFRS, Cameco has recorded its share of BPLP's IFRS transition adjustments. BPLP's transition adjustments relate largely to the recognition of previously unrecognized actuarial losses, as well as adjustments for changes in amounts eligible for capitalization, componentization of property, plant and equipment and the recognition of additional provisions as required under IFRS.
- (i) BPLP's policy choice under IFRS for defined benefit plans is to recognize all actuarial gains and losses in other comprehensive income. As a result of this policy choice, for all defined benefit plans existing at January 1, 2010, BPLP has recognized in retained earnings all cumulative actuarial losses. Cameco's share of this adjustment was a decrease to retained earnings of \$136,954,000. During 2010 the actuarial valuations for the pension plans were updated to reflect current market conditions and an actuarial loss was recorded. Cameco's share of this adjustment was a decrease to other comprehensive income of \$223,380,000.
- In 2005, BPLP sublet the four Bruce A reactors to a newly-formed partnership (the Bruce A Limited Partnership or "BALP"). BPLP continues to be responsible for the overall management of the site, including employment of the full workforce. BPLP and BALP entered into a services and cost sharing agreement to achieve an equitable allocation of certain operating costs, including employee pension and other post-retirement costs.
- As a result of being the employer of record, BPLP has legal liability for the pension and other post-retirement benefit plans and is required to recognize the entire amount of any actuarial gains and losses in other comprehensive income. These costs are shared with BALP through the services and cost sharing agreement with amounts recovered from BALP classified in earnings rather than other comprehensive income.
- (ii) Unlike Canadian GAAP, IFRS requires the cost of major inspections and overhauls to be recognized in the carrying amount of property, plant and equipment. It also requires that components of an item of property, plant and equipment with different useful lives be accounted for and depreciated separately.
- (iii) Under IFRS, unlike Canadian GAAP, provisions are required to be made when a constructive obligation exists. IFRS also varies from Canadian GAAP in its requirements for certain accruals to be made.

The effects of the IFRS transition adjustments were as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Accounts receivable (iii)	\$727
Supplies and prepaid expenses (iii)	1,043
Long-term receivables, investments and other (i)	(84,214)
Property, plant and equipment (ii)	8,753
Accounts payable and accrued liabilities (iii)	23,164
Current portion of of other liabilities	(23,479)
Provisions (iii)	(3,318)
Other liabilities (i),(iii)	(275,457)
Retained earnings (i),(ii),(iii)	352,781

<b>Consolidated Statements of Earnings and Comprehensive Income</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Products and services sold (i),(ii),(iii)	\$(618)	\$(12,298)
Depreciation, depletion and amortization (ii)	2,368	6,230
Finance costs	480	-
Gains on derivatives	(20)	-
Defined benefit plan actuarial losses (i)	223,380	223,380

- b) Under IFRS, and similar to Canadian GAAP, changes to a decommissioning liability to recognize the passage of time (unwinding of the discount or accretion) are required to be recorded. Under Canadian GAAP, the accretion was recorded as an operating cost and allocated to inventory while under IFRS, the unwinding of the discount is required to be reflected as a finance cost and does not qualify for capitalization. The effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Inventories	\$(10,321)
Provisions	3,209
Retained earnings	7,157
Other components of equity (foreign currency translation)	(45)

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Depreciation, depletion and amortization	\$(4,439)	\$(10,798)
Finance costs	3,192	9,568

- c) Cameco has elected, under IFRS 1, not to apply IAS 23 retrospectively to borrowing costs incurred on the construction of qualifying assets that commenced prior to January 1, 2010. Accordingly, Cameco has derecognized all borrowing costs that had been previously capitalized under Canadian GAAP through a charge to retained earnings. In addition, based on this election, borrowing costs incurred subsequent to the date of transition on qualifying assets where the construction of the asset commenced prior to January 1, 2010 are being expensed as incurred. The effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Property, plant and equipment	\$(366,149)
Retained earnings	366,149

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Depreciation, depletion and amortization	\$(958)	\$(2,670)
Finance costs	11,501	35,009

- d) IFRS requires the reversal of any previously recorded impairment losses where circumstances have changed such that the impairments have been reduced. The reversal of impairment losses was prohibited under Canadian GAAP. In 2000, as a result of depressed uranium prices, Cameco recorded a write-down relating to certain in situ recovery mine assets located in the United States. The amount of the write-down was determined based on estimated future net cash flows and uranium price forecasts. As a result of the strengthening of uranium prices since 2000, Cameco reassessed these previously impaired assets and based on their value in use, determined that a portion of these previous write-downs should be reversed. The reversal of these impairment losses has been recognized in cost of sales in the statements of earnings and the effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Property, plant and equipment	\$33,033
Inventory	364
Retained earnings	(33,912)
Other components of equity (foreign currency translation)	515

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Depreciation, depletion and amortization	\$404	\$688

- e) IFRS specifically precludes the inclusion of general overhead and administration expenses in the cost of an item of property, plant and equipment. Cameco reviewed the composition of its items of property, plant and equipment to assess whether the costs included related specifically to the construction of the asset, or whether they were general in nature and determined that certain costs should be expensed under IFRS. The effect of removing these costs from property, plant and equipment was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Property, plant and equipment	\$(7,205)
Retained earnings	7,205

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Depreciation, depletion and amortization	\$(109)	\$(321)

- f) Under IFRS, investments in equity-accounted investees are presented in the consolidated statements of financial position as a separate line item. Previously under Canadian GAAP, these investments were included in long-term receivables, investments and other. The effect of this reclassification was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Investments in equity-accounted investees	\$195,261
Long-term receivables, investments and other	(195,261)

- g) Cameco's policy choice under IFRS for defined benefit plans is to recognize all actuarial gains and losses in other comprehensive income. As a result of this policy choice, for all defined benefit plans existing at January 1, 2010, the Company has recognized in retained earnings \$14,404,000 of cumulative actuarial losses. The effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Long-term receivables, investments and other	\$(3,176)
Other liabilities	(10,327)
Retained earnings	13,519
Other components of equity (foreign currency translation)	(16)

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Administration	\$(295)	\$(885)

- h) Under IFRS, in-process research and development ("IPR&D") that meets the definition of an intangible asset is capitalized with amortization commencing when the asset is ready for use (i.e., when development is complete). Under Canadian GAAP, amortization of IPR&D capitalized as an intangible asset was commenced immediately, with the amortization period extending from the date of initial recognition to the date the completed asset will be available for use in commercial production. Cameco had been amortizing IPR&D related to the acquisition of its interest in equity-accounted investee GE-Hitachi Global Laser Enrichment LLC, a development-stage entity. Under IFRS, this amortization does not begin until development is complete. The effect of reversing this previously recognized amortization was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Investments in equity-accounted investees	\$26,878
Retained earnings	(27,248)
Other components of equity (foreign currency translation)	370

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Share of loss from equity-accounted investees	\$(2,859)	\$(8,557)

- i) Cameco has granted cash-settled phantom stock options to eligible non-North American employees. The Company applied IFRS 2 to its unsettled share-based compensation arrangements at January 1, 2010.

Cameco accounted for these share-based compensation arrangements at intrinsic value under Canadian GAAP. The related liability has been adjusted to reflect the fair value of the outstanding cash-settled phantom stock options to be consistent with the Company's accounting policies under IFRS. The effect of accounting for cash-settled share-based compensation transactions at fair value was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Accounts payable and accrued liabilities	\$(469)
Retained earnings	469

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Administration	\$212	\$(362)

- j) Under IFRS, decommissioning liabilities and waste provisions are presented in the consolidated statements of financial position as part of provisions. Previously under Canadian GAAP, these obligations were presented separately as provision for reclamation and other liabilities. The effect of this reclassification was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Provision for reclamation	\$261,686
Provisions	(299,814)
Other liabilities	38,128

- k) Cameco has elected, under IFRS 1, not to retrospectively recalculate, under IFRIC 1, the effect of each change in its reclamation provision prior to January 1, 2010. Instead, the liability and related assets and depreciation were measured as at the date of transition. Accordingly, Cameco has recalculated the provision and estimated the amount that would have been adjusted to the cost of the related asset by discounting the liability at the date of transition back to the date when the liability first arose, using its best estimate of the historical risk free rate that would have applied over the intervening period. In addition, the Company has calculated the accumulated depreciation on that amount as at the date of transition to IFRS based on the current estimate of the useful life of the asset.

The effect of the IFRS transition adjustments was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Property, plant and equipment	\$(51,731)
Provisions	(56,785)
Retained earnings	108,892
Other components of equity (foreign currency translation)	(376)

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Depreciation, depletion and amortization	\$(216)	\$(1,358)

- l)** IFRS requires that provisions such as those for environmental costs be recognized when it is probable that a restoration expense will be incurred and the associated costs can be reliably estimated. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure. Under IFRS, provisions for waste removal are measured initially at their present value using risk adjusted cash flows, with changes to the liability due to the passage of time (accretion) recorded as a finance cost. Under Canadian GAAP, discounting to reflect the time value of money is allowed, but not required. In the fuel services conversion processes, a certain amount of waste material is generated. Under Canadian GAAP, provisions for waste removal were measured using undiscounted estimated cash flows and recognized as an expense and a corresponding liability. The effect of discounting the provision upon transition to IFRS was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Provisions	\$796
Retained earnings	(796)

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Finance costs	\$325	\$977

- m)** Under IFRS, convertible debentures that contain a cash settlement feature are accounted for as a hybrid instrument with a debt component and a separate derivative representing the conversion option. The debt component is classified as a financial liability and accounted for at amortized cost using the effective interest rate method, while the conversion option is accounted for as a derivative and recorded at fair value with changes in fair value recorded in earnings.

Under Canadian GAAP, certain convertible debentures that contained a cash settlement feature were accounted for as a compound instrument with both a debt and equity component. Consistent with IFRS, the debt component was accounted for at amortized cost using the effective interest rate method; however, the conversion option was accounted for as an equity instrument with any changes in value not recognized.

The effect of accounting for the conversion option as a derivative at fair value was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Retained earnings	\$297,400
Share capital	(297,400)

- n) In accordance with IFRS 1, Cameco has elected to deem all foreign currency translation differences that existed at the date of transition to IFRS in respect of all foreign entities to be zero at the date of transition.

The effect was to increase foreign currency translation (other components of equity) and to decrease retained earnings by \$50,398,000 at September 30, 2010.

In addition to the above, cash flow hedging reserves of \$50,308,000 as at September 30, 2010 and available-for-sale assets reserves of \$683,000 at September 30, 2010 have been reclassified from accumulated other comprehensive income under Canadian GAAP to their respective reserve accounts within other components of equity under IFRS.

- o) Under IFRS, non-controlling interests are presented in the consolidated statement of financial position as equity but are presented separately from the parent shareholders' equity. Under Canadian GAAP, non-controlling interests were classified between total liabilities and equity and referred to as minority interest.
- p) The foregoing changes decreased (increased) the deferred tax amounts as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
BPLP transition adjustments (a)	\$88,181
Decommissioning liabilities - discounting (k)	30,655
Decommissioning liabilities - accretion (b)	2,242
Provision for waste (l)	(210)
Borrowing costs (c)	96,700
Impairment reversal (d)	(11,930)
Capitalized overhead (e)	1,903
IPR&D (h)	(9,407)
Share-based compensation (i)	92
Employee benefits (g)	3,649
	<b>\$201,875</b>

In addition, other components of equity of \$(172,000) as at September 30, 2010 have been adjusted to reflect the impact of foreign currency translation on the deferred tax balance.

The adjustments described above impacted income tax expense (recovery) on the consolidated statements of earnings as follows:

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
BPLP transition adjustments (a)	\$(545)	\$1,525
Decommissioning liabilities - discounting (k)	35	289
Decommissioning liabilities - accretion (b)	381	280
Provision for waste (l)	(86)	(258)
Borrowing costs (c)	(2,784)	(8,541)
Capitalized overhead (e)	29	85
IPR&D (h)	1,001	2,995
Share-based compensation (i)	(39)	44
Employee benefits (g)	80	240
Income tax recovery	\$(1,928)	\$(3,341)

The adjustment to other comprehensive income relating to actuarial losses in BPLP is net of taxes of \$55,844,000

- q) Under IFRS, a deferred tax liability (asset) is recognized for the difference in tax bases between jurisdictions as a result of an intra-group transfer of assets and consequently, the deferred tax is computed using the tax rate applicable to the purchaser. Under Canadian GAAP, a deferred tax liability (asset) was not recognized for the difference in tax bases between jurisdictions. Any taxes paid or recovered by the transferor were recognized as an asset or liability once the profit or loss was recognized by the consolidated entity. The IFRS adjustment is related to product sold by Cameco to subsidiaries and held in inventory at the transition date. The effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>	
Deferred tax liabilities	\$13,635	
Retained earnings	(13,635)	

  

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Income tax recovery	\$(6,882)	\$(14,175)

- r) Under IFRS, a deferred tax liability (asset) is recognized for exchange gains and losses related to foreign non-monetary assets and liabilities that are remeasured into the functional currency using historical exchange rates for tax purposes. Under Canadian GAAP, a deferred tax liability (asset) is not recognized for a temporary difference between the historical exchange rate and the current exchange rate translations of non-monetary assets and liabilities. The effect was as follows:

<b>Consolidated Statements of Financial Position</b>	<b>Sep 30/10</b>
Current tax liability	\$(786)
Deferred tax liabilities	(2,936)
Retained earnings	3,785
Other components of equity (foreign currency translation)	(63)

<b>Consolidated Statements of Earnings</b>	<b>Three Months Ended Sep 30/10</b>	<b>Nine Months Ended Sep 30/10</b>
Income tax recovery	\$(59)	\$(348)

- s) The above changes increased (decreased) retained earnings as follows:

	<b>Sep 30/10</b>
BPLP transition adjustments (a)	\$(352,781)
Decommissioning liabilities - accretion (b)	(7,157)
Borrowing costs (c)	(366,149)
Impairment reversal (d)	33,912
Capitalized overhead (e)	(7,205)
Employee benefits (g)	(13,519)
In-process research and development (h)	27,248
Share-based compensation (i)	(469)
Decommissioning liabilities - discounting (k)	(108,892)
Provision for waste - discounting (l)	796
Convertible debentures (m)	(297,400)
Other components of equity (n)	(50,398)
Deferred tax liability (p)	201,703
Deferred tax liabilities - intra-group transfer (q)	13,635
Deferred tax liabilities - foreign non-monetary assets (r)	(3,785)
	<b>\$(930,461)</b>

## Explanation of material adjustments to the cash flow statement for 2010

Consistent with the Company's accounting policy election under IAS 7, *Statement of Cash Flows*, interest paid has been reclassified as a financing activity. Under Canadian GAAP, it had been capitalized and included with additions to property, plant and equipment as an investing activity. The amounts reclassified were \$24,322,000 for the three months ended September 30, 2010 and \$51,835,000 for the nine months ended September 30, 2010.

There are no other material differences between the cash flow statement presented under IFRS and the cash flow statement presented under Canadian GAAP.

## 4. Accounting Standards

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

The following standards and amendments to existing standards have been published but are not effective for the year ended December 31, 2011, and have not been applied in preparing these condensed consolidated interim financial statements:

#### (i) Financial Instruments

In October 2010, the International Accounting Standards Board ("IASB") issued IFRS 9, *Financial Instruments* ("IFRS 9"). This standard is effective for periods beginning on or after January 1, 2013 and is part of a wider project to replace IAS 39, *Financial Instruments: Recognition and Measurement*. 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. Cameco is assessing the impact of this new standard on its financial statements.

#### (ii) Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10, *Consolidated Financial Statements* ("IFRS 10"). This standard is effective for periods beginning on or after January 1, 2013 and 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. Cameco is assessing the impact of this new standard on its financial statements.

#### (iii) Joint Arrangements

In May 2011, the IASB issued IFRS 11, *Joint Arrangements* ("IFRS 11"). This standard is effective for periods beginning on or after January 1, 2013 and 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. Cameco is assessing the impact of this new standard on its financial statements.

#### (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 is effective for periods beginning on or after January 1, 2013 and 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. Cameco is assessing the impact of this new standard on its financial statements.

#### (v) Fair Value Measurement

In May 2011, the IASB issued IFRS 13, *Fair Value Measurement* ("IFRS 13"). This standard is effective for periods beginning on or after January 1, 2013 and 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. Cameco is assessing the impact of this new standard on its financial statements.

**(vi) Employee Benefits**

In June 2011, the IASB issued an amended version of IAS 19, *Employee Benefits* (“IAS 19”). This amendment is effective for periods beginning on or after January 1, 2013 and 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. Cameco is assessing the impact of this revised standard on its financial statements.

**(vii) Presentation of Other Comprehensive Income**

In June 2011, the IASB issued an amended version of IAS 1, *Presentation of Financial Statements* (“IAS 1”). This amendment is effective for periods beginning on or after January 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. Cameco is assessing the impact of this revised standard on its financial statements.

**5. Inventories**

	Sep 30/11	Dec 31/10
<b>Uranium</b>		
Concentrate	\$500,962	\$385,242
Broken ore	41,028	12,138
	541,990	397,380
<b>Fuel Services</b>	147,862	135,710
<b>Total</b>	<b>\$689,852</b>	<b>\$533,090</b>

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

	Sep 30/11	Dec 31/10
<b>BPLP</b>		
Capital lease receivable from BALP <sup>(a)</sup>	\$88,764	\$91,608
Derivatives [note 16]	52,194	77,831
Available-for-sale securities		
Western Uranium Corporation	-	6,033
GoviEx Uranium (privately held)	22,040	23,017
Derivatives [note 16]	10,961	50,011
Advances receivable from Inkai JV LLP [note 21]	90,103	125,072
Other	84,577	60,550
	348,639	434,122
Less current portion	(39,190)	(91,447)
<b>Net</b>	<b>\$309,449</b>	<b>\$342,675</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.

## 7. Other Liabilities

	Sep 30/11	Dec 31/10
Deferred sales	\$38,011	\$17,004
Derivatives [note 16]	62,952	5,273
Accrued pension and post-retirement benefit liability	22,215	21,738
BPLP		
Accrued pension and post-retirement benefit liability <sup>(a)</sup>	518,505	375,430
Derivatives [note 16]	18,443	29,954
Other	6,870	9,270
	666,996	458,669
Less current portion	(129,999)	(53,192)
<b>Total</b>	<b>\$536,997</b>	<b>\$405,477</b>

- <sup>(a)</sup> During the quarter the actuarial valuations for our pension plans were updated to reflect current market conditions. As a result, for the three and nine months ended September 30, 2011, Cameco has recorded an actuarial loss of \$146,529,000 (2010 - \$223,380,000), on a pre-tax basis (Note 12).

## 8. Long-Term Debt

At September 30, 2011, Cameco had a \$500,000,000 unsecured revolving credit facility that was available until November 30, 2012. In addition to direct borrowings under the facility, up to \$100,000,000 could have been used for the issuance of letters of credit and, to the extent necessary, up to \$400,000,000 could have been allocated to provide liquidity support for the company's commercial paper program. The facility ranked equally with all of Cameco's other senior debt. At September 30, 2011, there were no amounts outstanding under this credit facility (2010 – nil).

On November 1, 2011, Cameco amended and extended the term of our \$500,000,000 unsecured revolving credit facility that was maturing November 30, 2012. This credit facility was increased to \$1,250,000,000 and now matures on November 1, 2016. Upon mutual agreement, the facility can be extended for an additional year on the anniversary date. In addition to direct borrowings under the facility, up to \$100,000,000 can be used for the issuance of letters of credit and, to the extent necessary, it may be used to provide liquidity support for the company's commercial paper program. The facility ranks equally with all of our other senior debt. As of November 4, 2011 there were no amounts outstanding under this facility. The agreement provides the ability to increase the revolving credit facility above \$1,250,000,000 by no less than increments of \$50,000,000, up to a total of \$1,750,000,000.

On November 1, 2011, Cameco cancelled our \$100 million unsecured revolving credit facility that was maturing February 4, 2012.

## 9. Share Capital

- (a) At September 30, 2011, there were 394,714,883 common shares outstanding.
- (b) Options in respect of 8,647,291 shares are outstanding under the stock option plan and are exercisable up to 2019. For the quarter ended September 30, 2011, 3,800 options were exercised resulting in the issuance of shares (2010 – 432,652). For the nine months ended September 30, 2011, 363,840 options were exercised resulting in the issuance of shares (2010 – 619,844).

## 10. Employee Benefit Expense

The following employee benefit expenses are included in cost of products and services sold, administration, exploration and research and development.

	Three Months Ended		Nine Months Ended	
	Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
Wages and salaries	\$127,199	\$112,637	\$366,044	\$335,727
Statutory and company benefits	17,352	17,273	63,847	60,690
Equity-settled share-based compensation	4,179	3,752	11,848	10,593
Expenses related to defined benefit plans	6,722	4,945	18,642	14,834
Contributions to defined contribution plans	4,550	4,428	18,250	13,306
Cash-settled share-based compensation	(2,740)	2,516	(9,985)	(3,099)
<b>Total</b>	<b>\$157,262</b>	<b>\$145,551</b>	<b>\$468,646</b>	<b>\$432,051</b>

## 11. Finance Costs

	Three Months Ended		Nine Months Ended	
	Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
Interest on long-term debt	\$14,463	\$14,874	\$42,793	\$43,035
Unwinding of discount on provisions	3,240	3,517	9,978	10,544
Other charges	83	2,071	2,223	6,729
Foreign exchange losses (gains)	(1,844)	1,792	(527)	4,677
Interest on short-term debt	443	554	1,479	1,458
<b>Total</b>	<b>\$16,385</b>	<b>\$22,808</b>	<b>\$55,946</b>	<b>\$66,443</b>

## 12. Income Taxes

	Three Months Ended		Nine Months Ended	
	Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
Earnings (loss) before income taxes				
Canada	\$(185,682)	\$(6,789)	\$(260,300)	\$(64,818)
Foreign	199,176	99,605	418,324	365,907
	<b>\$13,494</b>	<b>\$92,816</b>	<b>\$158,024</b>	<b>\$301,089</b>
Current income taxes (recovery)				
Canada	\$(10,422)	\$3,219	\$(10,847)	\$29,382
Foreign	9,866	5,698	27,002	19,437
	<b>\$(556)</b>	<b>\$8,917</b>	<b>\$16,155</b>	<b>\$48,819</b>
Deferred income taxes (recovery)				
Canada	\$(25,676)	\$(10,999)	\$(42,433)	\$(57,879)
Foreign	4,521	1,037	7,501	5,934
	<b>\$(21,155)</b>	<b>\$(9,962)</b>	<b>\$(34,932)</b>	<b>\$(51,945)</b>
<b>Income tax recovery</b>	<b>\$(21,711)</b>	<b>\$(1,045)</b>	<b>\$(18,777)</b>	<b>\$(3,126)</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 and 2005, which have increased Cameco's income for Canadian income tax purposes by approximately \$43,000,000, \$108,000,000 and \$197,000,000 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 \$31,000,000. 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 cumulative tax provision recorded, 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 2010 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 September 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$51,339	\$ -	\$51,339
Gains on derivatives designated as cash flow hedges	725	(181)	544
Gains on derivatives designated as cash flow hedges transferred to net earnings	(5,531)	1,469	(4,062)
Unrealized gains on assets available-for-sale	69	(9)	60
Gains on assets available-for-sale transferred to net earnings	(9)	1	(8)
Defined benefit plan actuarial losses	(146,529)	36,632	(109,897)
	<b>\$(99,936)</b>	<b>\$37,912</b>	<b>\$(62,024)</b>

**For the three months ended September 30, 2010**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$30,572	\$ -	\$30,572
Gains on derivatives designated as cash flow hedges	2,485	(659)	1,826
Gains on derivatives designated as cash flow hedges transferred to net earnings	(20,768)	6,008	(14,760)
Unrealized gains on assets available-for-sale	168	(29)	139
Losses on assets available-for-sale transferred to net earnings	18	(3)	15
Defined benefit plan actuarial losses	(223,380)	55,844	(167,536)
	<b>\$(210,905)</b>	<b>\$61,161</b>	<b>\$(149,744)</b>

**For the nine months ended September 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$39,900	\$ -	\$39,900
Gains on derivatives designated as cash flow hedges	4,998	(1,332)	3,666
Gains on derivatives designated as cash flow hedges transferred to net earnings	(20,872)	5,578	(15,294)
Unrealized gains on assets available-for-sale	860	(116)	744
Gains on assets available-for-sale transferred to net earnings	(2,129)	281	(1,848)
Defined benefit plan actuarial losses	(146,529)	36,632	(109,897)
	<b>\$(123,772)</b>	<b>\$41,043</b>	<b>\$(82,729)</b>

**For the nine months ended September 30, 2010**

	<b>Before tax</b>	<b>Income tax recovery (expense)</b>	<b>Net of tax</b>
Exchange differences on translation of foreign operations	\$22,150	\$ -	\$22,150
Gains on derivatives designated as cash flow hedges	14,925	(2,795)	12,130
Gains on derivatives designated as cash flow hedges transferred to net earnings	(72,430)	21,152	(51,278)
Unrealized gains on assets available-for-sale	1,233	(161)	1,072
Gains on assets available-for-sale transferred to net earnings	(3,023)	409	(2,614)
Defined benefit plan actuarial losses	(223,380)	55,844	(167,536)
	<b>\$(260,525)</b>	<b>\$74,449</b>	<b>\$(186,076)</b>

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

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>Sep 30/11</b>	<b>Sep 30/10</b>	<b>Sep 30/11</b>	<b>Sep 30/10</b>
Changes in non-cash working capital:				
Accounts receivable	\$(61,100)	\$(87,975)	\$169,059	\$97,509
Inventories	(548)	(65,884)	(117,127)	(50,914)
Supplies and prepaid expenses	(8,509)	(10,818)	(12,540)	(3,329)
Accounts payable and accrued liabilities	40,241	29,096	1,574	(146,198)
Other	10,404	(13,559)	(18,504)	(20,967)
<b>Total</b>	<b>\$(19,512)</b>	<b>\$(149,140)</b>	<b>\$22,462</b>	<b>\$(123,899)</b>

**14. Stock Option Plan**

The Company has established a stock option plan under which options to purchase common shares may be granted to officers and other 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. Options have not been awarded to directors since 2003 and the plan has been amended to preclude the issue of options to directors.

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 26,456,279 shares have been issued.

Cameco records compensation expense with an offsetting credit to contributed surplus to reflect the estimated fair value of stock options granted to employees. For the quarter ended September 30, 2011, the amount recorded was \$2,349,000 (2010 - \$1,324,000). For the nine months ended September 30, 2011, the amount recorded was \$11,970,000 (2010 - \$7,645,000).

The fair value of the options granted each year was determined using the Black-Scholes option-pricing model with the following weighted average assumptions:

	<b>Nine Months Ended</b>	
	<b>Sep 30/11</b>	<b>Sep 30/10</b>
Number of options granted	1,630,069	1,515,945
Average strike price	\$39.10	\$28.90
Expected dividend	\$0.40	\$0.28
Expected volatility	39%	36%
Risk-free interest rate	2.5%	2.1%
Expected life of option	4.5 years	4.2 years
Expected forfeitures	15%	15%
Weighted average grant date fair values	\$12.57	\$8.46

## 15. Commitments and Contingencies

(a) On February 12, 2004, Cameco, Cameco Bruce Holdings II Inc., BPC Generation Infrastructure Trust ("BPC") and TransCanada Pipelines Limited ("TransCanada") (collectively, the "Consortium"), sent a notice of claim to British Energy Limited and British Energy International Holdings Limited (collectively, "BE") requesting, amongst other things, indemnification for breach of a representation and warranty contained in the February 14, 2003, Amended and Restated Master Purchase Agreement. The alleged breach is that the Unit 8 steam generators were not "in good condition, repair and proper working order, having regard to their use and age." This defect was discovered during a planned outage conducted just after closing. As a result of this defect, the planned outage had to be significantly extended. The Consortium has claimed damages in the amount of \$64,558,200 being 79.8% of the \$80,900,000 of damages actually incurred, plus an unspecified amount to take into account the reduced operating life of the steam generators. By agreement of the parties, an arbitrator has been appointed to arbitrate the claims.

The Consortium served its claim on October 21, 2008, and has amended it as required, most recently on August 7, 2009. BE served its answer and counter-statement on December 22, 2008, most recently amended on March 25, 2010, and the Consortium served its reply and answer to counter-statement on January 22, 2009, most recently amended on August 7, 2009.

The Unit 8 steam generators require on-going monitoring and maintenance as a result of the defect. In addition to the \$64,558,200 in damages sought in the notice of claim, the claim seeks an additional \$4,900,000 spent on inspection, monitoring and maintenance of Unit 8, and \$31,900,000 in costs for future monitoring and maintenance, as well as repair costs and lost revenue due to anticipated unplanned outages as a consequence of the defect in Unit 8. The initial claim had also sought damages for the early replacement of the Unit 8 steam generators due to the defect shortening their useful operating lives. However, subsequent inspection data and analysis of the condition of the Unit 8 steam generators indicates that they will continue to function until the end of the Consortium's lease of the Bruce Power facility in 2018, as was expected at the time the MPA was entered into. The claim for early replacement was thus abandoned via an amendment to the claim on August 7, 2009. The arbitration hearing was completed on November 23, 2010 and final oral arguments were heard July 19 through 21, 2011 and a decision is pending.

In anticipation of this claim, BE issued on February 10, 2006, and then served on Ontario Power Generation Inc. ("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 completion of the arbitration hearing.

(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 2011 to 2018:
- i) Guarantees to customers under power sales agreements of up to \$19,000,000. At September 30, 2011, Cameco's actual exposure under these agreements was \$13,300,000.
  - 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 2011, BPLP recorded \$351,000,000 under this agreement which was recognized as revenue with Cameco's share being \$110,900,000.

## 16. Derivatives

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

### As at September 30, 2011

	Cameco	BPLP	Total
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(2,057)	\$9,794	\$7,737
Foreign currency contracts	(56,983)	-	(56,983)
Interest rate contracts	7,049	-	7,049
Cash flow hedges:			
Energy and sales contracts	-	23,957	23,957
<b>Net</b>	<b>\$(51,991)</b>	<b>\$33,751</b>	<b>\$(18,240)</b>
Classification:			
Current portion of long-term receivables, investments and other [note 6]	\$2,587	\$36,602	\$39,189
Long-term receivables, investments and other [note 6]	8,374	15,592	23,966
Current portion of other liabilities [note 7]	(59,569)	(14,198)	(73,767)
Other liabilities [note 7]	(3,383)	(4,245)	(7,628)
<b>Net</b>	<b>\$(51,991)</b>	<b>\$33,751</b>	<b>\$(18,240)</b>

**As at December 31, 2010**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(3,864)	\$18,877	\$15,013
Foreign currency contracts	47,144	-	47,144
Interest rate contracts	1,458	-	1,458
Cash flow hedges:			
Energy and sales contracts	-	29,000	29,000
<b>Net</b>	<b>\$44,738</b>	<b>\$47,877</b>	<b>\$92,615</b>
Classification:			
Current portion of long-term receivables, investments and other [note 6]	\$46,629	\$44,505	\$91,134
Long-term receivables, investments and other [note 6]	3,382	33,326	36,708
Current portion of other liabilities [note 7]	(377)	(20,662)	(21,039)
Other liabilities [note 7]	(4,896)	(9,292)	(14,188)
<b>Net</b>	<b>\$44,738</b>	<b>\$47,877</b>	<b>\$92,615</b>

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

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

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$697	\$(1,884)	\$(1,187)
Foreign currency contracts	(79,999)	-	(79,999)
Interest rate contracts	6,009	-	6,009
Cash flow hedges:			
Energy and sales contracts	-	(627)	(627)
<b>Net</b>	<b>\$(73,293)</b>	<b>\$(2,511)</b>	<b>\$(75,804)</b>

**For the three months ended September 30, 2010**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$2,599	\$(3,315)	\$(716)
Foreign currency contracts	36,940	-	36,940
Interest rate contracts	3,234	-	3,234
Cash flow hedges:			
Energy and sales contracts	-	(339)	(339)
<b>Net</b>	<b>\$42,773</b>	<b>\$(3,654)</b>	<b>\$39,119</b>

**For the nine months ended September 30, 2011**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$2,069	\$(1,746)	\$323
Foreign currency contracts	(46,339)	-	(46,339)
Interest rate contracts	7,882	-	7,882
Cash flow hedges:			
Energy and sales contracts	-	(2,082)	(2,082)
<b>Net</b>	<b>\$(36,388)</b>	<b>\$(3,828)</b>	<b>\$(40,216)</b>

**For the nine months ended September 30, 2010**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(637)	\$(2,932)	\$(3,569)
Foreign currency contracts	22,999	-	22,999
Interest rate contracts	4,582	-	4,582
Cash flow hedges:			
Energy and sales contracts	-	(1,963)	(1,963)
<b>Net</b>	<b>\$26,944</b>	<b>\$(4,895)</b>	<b>\$22,049</b>

Over the next 12 months, based on current exchange rates, Cameco expects an estimated \$18,025,000 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.

## 17. 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 2011 was 394,642,475 (2010 – 392,987,679).

	Three Months Ended		Nine Months Ended	
	Sep 30/11	Sep 30/10	Sep 30/11	Sep 30/10
<b>Basic earnings per share computation</b>				
Net earnings attributable to equity holders	\$39,452	\$97,513	\$185,590	\$310,850
Weighted average common shares outstanding	394,712	393,100	394,642	392,988
<b>Basic earnings per common share</b>	<b>\$0.10</b>	<b>\$0.25</b>	<b>\$0.47</b>	<b>\$0.79</b>
<b>Diluted earnings per share computation</b>				
Net earnings attributable to equity holders	\$39,452	\$97,513	\$185,590	\$310,850
Weighted average common shares outstanding	394,712	393,100	394,642	392,988
Dilutive effect of stock options	474	1,483	994	1,645
Weighted average common shares outstanding, assuming dilution	395,186	394,583	395,636	394,633
<b>Diluted earnings per common share</b>	<b>\$0.10</b>	<b>\$0.25</b>	<b>\$0.47</b>	<b>\$0.79</b>

## 18. 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 summary of significant accounting policies.

### (a) Business Segments

#### For the three months ended September 30, 2011

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$331,500	\$80,563	\$114,266	\$623	\$526,952
Expenses					
Products and services sold	164,704	64,816	54,926	73	284,519
Depreciation, depletion and amortization	34,279	6,089	18,455	4,597	63,420
<b>Cost of sales</b>	<b>198,983</b>	<b>70,905</b>	<b>73,381</b>	<b>4,670</b>	<b>347,939</b>
<b>Gross profit (loss)</b>	<b>132,517</b>	<b>9,658</b>	<b>40,885</b>	<b>(4,047)</b>	<b>179,013</b>
Exploration	35,619	-	-	-	35,619
Cigar Lake remediation	576	-	-	-	576
Loss on sale of assets	418	-	-	-	418
Share of loss from equity-accounted investees	686	757	-	-	1,443
Other expense	1,036	-	-	-	1,036
Non-segmented expenses					126,427
<b>Earnings (loss) before income taxes</b>	<b>94,182</b>	<b>8,901</b>	<b>40,885</b>	<b>(4,047)</b>	<b>13,494</b>
Income tax recovery					(21,711)
<b>Net earnings</b>					<b>\$35,205</b>

**For the three months ended September 30, 2010**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$239,655	\$64,278	\$114,866	\$676	\$419,475
Expenses					
Products and services sold	97,798	47,965	57,388	88	203,239
Depreciation, depletion and amortization	33,742	5,426	16,600	4,621	60,389
<b>Cost of sales</b>	<b>131,540</b>	<b>53,391</b>	<b>73,988</b>	<b>4,709</b>	<b>263,628</b>
<b>Gross profit (loss)</b>	<b>108,115</b>	<b>10,887</b>	<b>40,878</b>	<b>(4,033)</b>	<b>155,847</b>
Exploration	35,430	-	-	-	35,430
Cigar Lake remediation	6,622	-	-	-	6,622
Gain on sale of assets	(481)	-	-	-	(481)
Share of loss from equity-accounted investees	875	749	-	-	1,624
Other expense	408	-	-	-	408
Non-segmented expenses					19,428
<b>Earnings (loss) before income taxes</b>	<b>65,261</b>	<b>10,138</b>	<b>40,878</b>	<b>(4,033)</b>	<b>92,816</b>
Income tax recovery					(1,045)
<b>Net earnings</b>					<b>\$93,861</b>

**For the nine months ended September 30, 2011**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$885,068	\$199,478	\$320,898	\$1,473	\$1,406,917
Expenses					
Products and services sold	487,495	153,904	179,755	147	821,301
Depreciation, depletion and amortization	79,077	16,528	53,013	13,673	162,291
<b>Cost of sales</b>	<b>566,572</b>	<b>170,432</b>	<b>232,768</b>	<b>13,820</b>	<b>983,592</b>
<b>Gross profit (loss)</b>	<b>318,496</b>	<b>29,046</b>	<b>88,130</b>	<b>(12,347)</b>	<b>423,325</b>
Exploration	70,577	-	-	-	70,577
Cigar Lake remediation	4,113	-	-	-	4,113
Loss on sale of assets	1,113	-	-	-	1,113
Share of loss from equity-accounted investees	3,665	1,908	-	-	5,573
Other income	(3,053)	-	-	-	(3,053)
Non-segmented expenses					186,978
<b>Earnings (loss) before income taxes</b>	<b>242,081</b>	<b>27,138</b>	<b>88,130</b>	<b>(12,347)</b>	<b>158,024</b>
Income tax recovery					(18,777)
<b>Net earnings</b>					<b>\$176,801</b>

**For the nine months ended September 30, 2010**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$900,560	\$195,214	\$352,688	\$1,783	\$1,450,245
Expenses					
Products and services sold	460,374	131,361	166,342	225	758,302
Depreciation, depletion and amortization	97,666	12,160	48,271	14,544	172,641
<b>Cost of sales</b>	<b>558,040</b>	<b>143,521</b>	<b>214,613</b>	<b>14,769</b>	<b>930,943</b>
<b>Gross profit (loss)</b>	<b>342,520</b>	<b>51,693</b>	<b>138,075</b>	<b>(12,986)</b>	<b>519,302</b>
Exploration	68,340	-	-	-	68,340
Cigar Lake remediation	14,460	-	-	-	14,460
Gain on sale of assets	(297)	-	-	-	(297)
Share of loss from equity-accounted investees	2,181	2,216	-	-	4,397
Other income	(2,159)	-	-	-	(2,159)
Non-segmented expenses					133,472
<b>Earnings (loss) before income taxes</b>	<b>259,995</b>	<b>49,477</b>	<b>138,075</b>	<b>(12,986)</b>	<b>301,089</b>
Income tax recovery					(3,126)
<b>Net earnings</b>					<b>\$304,215</b>

**19. Talvivaara Agreement**

On February 7, 2011, Cameco signed two agreements with Talvivaara Mining Company Plc. to buy uranium produced at the Sotkamo nickel-zinc mine in Finland. Under the first agreement with Talvivaara, Cameco will provide an up-front payment, to a maximum of \$60,000,000 (US) to cover certain construction costs. This amount will be repaid through deliveries of uranium concentrate. Once the full amount has been repaid, Cameco will continue to purchase the uranium concentrates produced at the Sotkamo mine through a second agreement which provides for the purchase of uranium using a pricing formula that references market prices at the time of delivery. The second agreement expires on December 31, 2027.

**20. Hathor Offer**

On August 30, 2011, Cameco made an all-cash offer to acquire all the outstanding shares of Hathor Exploration Ltd. (Hathor) for a price of \$3.75 per share in a transaction which values the fully diluted share capital of Hathor at approximately \$520,000,000. On October 19, 2011, Hathor announced that it had entered into an agreement with Rio Tinto pursuant to which Rio Tinto will make an offer for all of the common shares of Hathor. On October 31, 2011, Cameco announced the extension of the expiry date of our offer to November 14, 2011.

**21. 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.

In addition to their salaries, Cameco also provides non-cash benefits to executive officers and vice-presidents, and contributes to pension plans on their behalf. Senior management and directors also participate in the Company's share-based compensation plans (see note 22 of the 2010 consolidated financial statements).

Executive officers are subject to terms of notice ranging from three to six months. Upon resignation at the Company's request, they are entitled to termination benefits up to the lesser of 24 months or the period remaining until age 65. The termination benefits include gross salary plus the target short-term incentive bonus for the year in which termination occurs.

Compensation for key management personnel was comprised of:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>Sep 30/11</b>	<b>Sep 30/10</b>	<b>Sep 30/11</b>	<b>Sep 30/10</b>
Short-term employee benefits	\$7,109	\$6,004	\$19,029	\$17,592
Post-employment benefits	1,139	1,440	3,534	4,245
Share-based compensation	2,022	1,447	7,496	5,774
	\$10,270	\$8,891	\$30,059	\$27,611

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 2011, Cameco paid Points Athabasca Contracting Ltd. \$46,900,000 (2010 - \$19,000,000) 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 \$3,700,000 (2010 - \$1,100,000).

#### **Other Related Party Transactions**

	<b>Transaction Value</b>		<b>Transaction Value</b>		<b>Balance Outstanding</b>	
	<b>Three Months Ended</b>	<b>Three Months Ended</b>	<b>Nine Months Ended</b>	<b>Nine Months Ended</b>	<b>As at</b>	<b>As at</b>
	<b>Sep 30/11</b>	<b>Sep 30/10</b>	<b>Sep 30/11</b>	<b>Sep 30/10</b>	<b>Sep 30/11</b>	<b>Sep 30/10</b>
<b>Sale of goods and services</b>						
Jointly Controlled Entities						
Bruce Power L.P.	\$6,530	\$11,730	\$20,804	\$28,591	\$10,816	\$29,814
<b>Other</b>						
Jointly Controlled Entities						
Interest income (Inkai)	522	956	1,725	2,619	90,103	148,834
Associates						
Interest expense	(444)	(555)	(1,479)	(1,458)	83,205	80,369

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 loan facility is \$370,000,000 (US) and advances under the facility bear interest at a rate of LIBOR plus 2%. At September 30, 2011, \$216,822,000 (US) of principal and interest was outstanding (December 31, 2010 - \$314,378,000 (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 September 30, 2011, \$80,090,000 (US) of principal and interest was outstanding (December 31, 2010 - \$78,579,000 (US)).

## **22. Comparative Figures**

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