



**PRESS RELEASE**

(Stock Symbol "CLT" – TSX)

August 7, 2009

Calgary, Alberta

**CELTIC REPORTS FINANCIAL AND OPERATING RESULTS FOR THE SECOND QUARTER OF 2009**

(\$ thousands, unless otherwise indicated)	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
<b>FINANCIAL</b>						
Revenue, before royalties and financial derivatives	<b>30,668</b>	80,220	-62%	<b>72,102</b>	137,591	-48%
Funds from operations	<b>20,008</b>	36,787	-46%	<b>48,148</b>	65,085	-26%
Basic (\$/share)	<b>0.46</b>	0.92	-50%	<b>1.14</b>	1.67	-32%
Diluted (\$/share)	<b>0.46</b>	0.90	-49%	<b>1.13</b>	1.65	-32%
Net loss	<b>(5,459)</b>	(9,116)	-40%	<b>(10,498)</b>	-16,491	-36%
Basic (\$/share)	<b>(0.13)</b>	(0.23)	-43%	<b>(0.25)</b>	-0.42	-40%
Diluted (\$/share)	<b>(0.13)</b>	(0.23)	-43%	<b>(0.25)</b>	-0.42	-40%
Capital expenditures, net of dispositions	<b>36,619</b>	67,736	-46%	<b>78,201</b>	100,345	-22%
Total assets				<b>663,531</b>	572,691	16%
Bank debt, net of working capital				<b>145,976</b>	156,483	-7%
Bank debt, net of working capital, excluding non-cash financial instruments				<b>157,619</b>	124,179	27%
Shareholders' equity				<b>394,870</b>	304,523	30%
Weighted average common shares outstanding (thousands)						
Basic	<b>43,486</b>	40,148	8%	<b>42,402</b>	38,924	9%
Diluted	<b>43,792</b>	40,822	7%	<b>42,583</b>	39,392	8%
<b>OPERATIONS</b>						
Production						
Oil (bbls/d)	<b>2,939</b>	3,367	-13%	<b>3,268</b>	3,338	-2%
Gas (mcf/d)	<b>47,822</b>	44,852	7%	<b>52,737</b>	41,785	26%
Combined (BOE/d)	<b>10,909</b>	10,842	1%	<b>12,057</b>	10,302	17%
Production per million shares (BOE/d)	<b>251</b>	270	-7%	<b>284</b>	265	7%
Realized sales prices, after financial instruments						
Oil (\$/bbl)	<b>86.32</b>	90.48	-5%	<b>82.32</b>	85.87	-4%
Gas (\$/mcf)	<b>3.77</b>	9.52	-60%	<b>4.64</b>	9.05	-49%
Operating netbacks (\$/BOE)						
Oil and gas revenue, before hedging	<b>30.88</b>	81.31	-62%	<b>33.02</b>	73.39	-55%
Realized gain (loss) on financial instruments	<b>8.90</b>	-13.82		<b>9.54</b>	-8.85	
Realized sales price, after hedging	<b>39.78</b>	67.49	-41%	<b>42.56</b>	64.54	-34%
Royalties	<b>(4.05)</b>	(17.39)	-77%	<b>(6.50)</b>	(16.30)	-60%
Production expense	<b>(12.13)</b>	(9.59)	26%	<b>(11.08)</b>	(9.98)	11%
Transportation expense	<b>(0.54)</b>	(0.57)	-5%	<b>(0.51)</b>	(0.65)	-22%
Operating netback	<b>23.06</b>	39.94	-42%	<b>24.47</b>	37.61	-35%
Drilling activity						
Total wells	<b>9</b>	10	-10%	<b>24</b>	25	-4%
Working interest wells	<b>8.7</b>	8.6	1%	<b>21.4</b>	20.9	2%
Success rate on working interest wells	<b>100%</b>	100%	0%	<b>91%</b>	86%	6%
Undeveloped land (acres)						
Gross				<b>344,846</b>	319,882	8%
Net				<b>272,000</b>	250,113	9%

## Message to Shareholders

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders the Company's activities in the second quarter of 2009. During the quarter, Celtic drilled 9 (8.7 net) wells with an overall success rate of 100%. For five weeks during the second quarter, Celtic had approximately 9,000 BOE per day shut-in as a result of the scheduled maintenance operations at the KA Gas Plant. During the KA Gas Plant turnaround, which occurs every four to five years, Celtic was able to divert some production to the K3 Gas Plant. Despite the shut-in production, Celtic achieved growth in production during the second quarter of 2009 when compared to the second quarter of 2008. Production during the quarter averaged 10,909 BOE per day, an increase of 1% from 10,842 BOE per day in the second quarter of 2008. Production during the second quarter of 2009 would have been in excess of 14,000 BOE per day, had the Company not been required to shut-in any production. In the second quarter of 2009, Celtic recorded funds from operations of \$20.0 million (\$0.46 per share, diluted), compared to \$36.8 million (\$0.90 per share, diluted) reported in the same quarter of the previous year. Lower funds from operations in 2009 were primarily due to significantly lower realized natural gas prices compared to the previous year.

All of Celtic's drilling activity during the second quarter of 2009 took place in the Greater Kaybob area of West Central Alberta, where 9 (8.7 net) wells were drilled with an overall success rate of 100%. All nine wells were horizontals with multi-fracture completions.

At Kaybob South, Celtic drilled three horizontal wells targeting the Triassic Montney formation. These wells are expected to be put on production later in the third quarter in anticipation of higher natural gas prices at that time.

At KayFox, Celtic drilled four horizontal wells. These wells were completed in the Triassic Montney formation in late July and are expected to be put on production in August 2009.

At Lower Kaybob South, Celtic drilled two horizontal wells and completed both wells in the Cretaceous Bluesky formation. The first well (68.6% BPPO and 50% APPO) produced natural gas at an average rate of 6.5 MMCF (gross) per day during a four day test. The second well (100% BPPO and 59.3% APPO) produced natural gas at an average rate of 10.7 MMCF per day during a four day test. These Bluesky wells also produce approximately 40 to 50 barrels of NGLs per MMCF per day of raw gas. The Company is pleased with the initial results from its Bluesky wells and plans to drill additional wells targeting the Bluesky zone in the second half of 2009.

At June 30, 2009, the Company's undeveloped land holdings in all areas increased to 344,846 (272,000 net) acres. With this inventory of land and with plans to continue developing its Kaybob prospects, Celtic continues to generate numerous drilling locations that will provide continued growth over the next few years. In addition to the Montney and Bluesky reservoirs, Celtic plans to test its horizontal drilling with multi fracture completions in the Nordegg and Notikewin zones at Kaybob during the second half of 2009.

Celtic has maintained its planned 2009 capital expenditure budget of \$150.0 million that it established back in November 2008. While many of the Company's peers have reduced their capital spending plans as a result of lower commodity prices, Celtic has been able to maintain its capital spending plans primarily due to a strong hedge book and the positive impact of Alberta's royalty incentives.

Oil and gas producers, like Celtic, are continually exposed to fluctuations in commodity prices that are beyond the control of the companies that produce hydrocarbons. In order to mitigate this risk and provide certainty to a portion of its cash flow supporting its capital investment program, Celtic employs an active risk management program. The Company's outstanding financial derivative contracts relating to its oil production, NYMEX to AECO basis differential, currency exchange rates and interest rates on debt are disclosed in detail in the accompanying notes to the financial statements. For the six months ended June 30, 2009, the Company realized \$19.7 million in gains from all of its financial instrument contracts. The mark-to-market value of remaining financial instrument contracts as at June 30, 2009 were valued at \$16.4 million, before the effect of income taxes.

The new royalty incentives announced by the Alberta Government will benefit the Company significantly until expiry on March 31, 2011. The Drilling Royalty Credit (“DRC”) provides companies with a \$200 per metre credit on new wells drilled that may be applied against corporate crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% for Celtic. During the second quarter of 2009, Celtic earned \$6.5 million of credits from its drilling activity. Based on estimated crown royalties payable during the quarter, the Company could have reduced capital expenditures by \$1.9 million during the quarter. However, since the DRC has not yet been passed into law, Celtic has not accrued reductions to capital expenditures during the second quarter. It is anticipated that the DRC will become law during the third quarter of 2009.

The New Well Royalty Reduction (“NWRR”) was also announced recently and provides for a flat 5% royalty on new wells brought on production after March 31, 2009. This program applies to all new wells brought on production prior to April 1, 2011. The 5% royalty remains in effect for twelve producing months or for the first 500,000 MCF equivalent of gas (or 50,000 barrels of oil equivalent) produced, whichever comes first. Celtic’s horizontal wells at Kaybob will benefit significantly from this program since the flat 5% royalty will replace first year royalty rates in the 22% to 35% range in a \$3.57 to \$7.14 per GJ AECO gas price environment.

With the benefit of the NWRR incentive program and given Celtic’s ability to claim its calculated Gas Cost Allowance (“GCA”), net corporate royalties for the remainder of 2009 are expected to be approximately 14%. For the second half of 2009, Celtic is forecasting average commodity prices of US\$62.55 per barrel for WTI oil, US\$5.05 per MMBTU for NYMEX natural gas, \$4.30 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.903.

### **Highlights - Second Quarter 2009**

The three months ended June 30, 2009 was another successful quarter in the execution of the Company’s growth strategy. Highlights for the second quarter of 2009 are as follows:

- Drilled 9 (8.7 net working interest) natural gas wells during the quarter resulting in an overall success rate of 100%;
- Increased average daily production by 1% to 10,909 BOE per day, up from 10,842 BOE per day in the second quarter of 2008, despite having approximately 9,000 BOE per day shut-in for five weeks during plant turnaround operations;
- Generated \$20.0 million in funds from operations for the three month period ended June 30, 2009, down 46% from \$36.8 million in the same quarter of the previous year. Reported funds from operations per share, diluted, of \$0.46, a decrease of 49% from \$0.90 per share in the second quarter of the previous year;
- Received an average operating netback of \$23.06 per BOE, down 42% from \$39.94 per BOE in the corresponding quarter of 2008.

### **Production**

Oil and gas production in the second quarter of 2009 increased 1% to average 10,909 BOE per day compared to 10,842 BOE per day in the same quarter of 2008. Production per million shares outstanding for the three months ended June 30, 2009 averaged 251 BOE per day, down 7% from 270 BOE per day in the corresponding quarter of the previous year.

Oil and gas production for the six months ended June 30, 2009 increased 17% to average 12,057 BOE per day compared to 10,302 BOE per day in the corresponding period of 2008. Production per million shares outstanding for the six months ended June 30, 2009 averaged 284 BOE per day, up 7% from 265 BOE per day in the corresponding period of the previous year.

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller and Michichi and its primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont, with future oil development potential at Edward/Figure Lake. In Northern Alberta, the Company produces light oil primarily from Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob, Fox Creek and Swan Hills. West Central Alberta was the Company's most active drilling area in the first six months of 2009.

## **Revenue**

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the three months ended June 30, 2009, was \$30.7 million, a decrease of 62% compared to \$80.2 million in the same quarter of the previous year. Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the six months ended June 30, 2009, was \$72.1 million, a decrease of 48% compared to \$137.6 million in the same period of the previous year.

Lower revenue in 2009 was due to significantly lower natural gas prices that more than offset increased production levels.

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the three months ended June 30, 2009 was \$39.78 per BOE, a decrease of 41% compared to the corresponding three month period of the previous year. The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the six months ended June 30, 2009 was \$42.56 per BOE, a decrease of 34% compared to the corresponding six month period of the previous year.

## **Oil Operations**

Oil production for the second quarter ended June 30, 2009 averaged 2,939 barrels per day, a decrease of 13% compared to the same quarter of the previous year. Oil production for the six months ended June 30, 2009 averaged 3,268 barrels per day, a decrease of 2% compared to the same period of the previous year.

The average price received for oil sales, after realized financial instruments, for the second quarter ended June 30, 2009 was \$86.32 (\$55.30 before financial instruments) per barrel, down 5% from the average price of \$90.48 (\$112.43 before financial instruments) per barrel received in the second quarter of 2008. The average price received for oil sales, after realized financial instruments, for the six months ended June 30, 2009 was \$82.32 (\$49.67 before financial instruments) per barrel, down 4% from the average price of \$85.87 (\$100.63 before financial instruments) per barrel received in the first six months of 2008.

For the quarter ended June 30, 2009, average oil royalties were 12.9% of revenue, after financial instruments (20.2% of revenue, before financial instruments). In the first quarter of the previous year, average oil royalties were 31.4% of revenue, after financial instruments (25.3% of revenue, before financial instruments). For the six months ended June 30, 2009, average oil royalties were 15.8% of revenue, after financial instruments (26.2% of revenue, before financial instruments). In the first six months of the previous year, average oil royalties were 29.4% of revenue, after financial instruments (25.1% of revenue, before financial instruments).

Lower oil royalty rates in 2009, before financial instruments, reflect the lower rates calculated with lower oil selling prices.

Transportation expenses for oil production in the second quarter of 2009 averaged \$0.35 per barrel compared to \$0.55 per barrel in the second quarter of 2008. Transportation expenses for oil production during the six month period ended June 30, 2009 averaged \$0.35 per barrel compared to \$0.61 per barrel in the corresponding period of 2008.

Lower per unit transportation expenses in 2009 reflect the larger portion of newer NGL production from Kaybob which is mostly pipeline connected and therefore less expensive to transport compared to trucking oil.

For the second quarter ended June 30, 2009, oil production expenses were \$13.97 per barrel. In the same quarter of the previous year, oil production expenses were \$12.54 per barrel. For the six months ended June 30, 2009, oil production expenses were \$13.91 per barrel. In the same period of the previous year, oil production expenses were \$13.53 per barrel.

## **Gas Operations**

Gas production for the second quarter ended June 30, 2009 averaged 47,822 MCF per day, an increase of 7% compared to the corresponding quarter of the previous year. Gas production for the six months ended June 30, 2009 averaged 52,737 MCF per day, an increase of 26% compared to the corresponding period of the previous year.

Increases in gas production in 2009 were primarily a result of Celtic's successful drilling results in its resource development prospect located at Kaybob, Alberta.

The average price received for gas sales, after realized financial instruments, for the second quarter ended June 30, 2009 was \$3.77 (\$3.65 before financial instruments) per MCF, down 60% from the average price of \$9.52 (\$11.21 before financial instruments) per MCF received in the second quarter of 2008. The average price received for gas sales, after realized financial instruments, for the six months ended June 30, 2009 was \$4.64 (\$4.48 before financial instruments) per MCF, down 49% from the average price of \$9.05 (\$10.05 before financial instruments) per MCF received in the first six months of 2008.

For the quarter ended June 30, 2009, average gas royalties were 6.4% of revenue, after financial instruments (6.6% of revenue, before financial instruments). In the second quarter of the previous year, average gas royalties were 21.7% of revenue, after financial instruments (18.6% of sales, before financial instruments). For the six month period ended June 30, 2009, average gas royalties were 14.7% of revenue, after financial instruments (15.4% of revenue, before financial instruments). In the first six months of the previous year, average gas royalties were 15.9% of revenue, after financial instruments (19.0% of revenue, before financial instruments).

Lower gas royalty rates in 2009, before financial instruments, were primarily a result of lower natural gas selling prices and longer depth horizontal wells which receive favourable treatment under the new royalty framework program. In addition, royalties are reduced further as the Company continues to receive GCA which does not fluctuate with gas prices.

Transportation expenses for the second quarter ended June 30, 2009 were \$0.10 per MCF, unchanged from \$0.10 per MCF for the same quarter in the previous year. Transportation expenses for the six months ended June 30, 2009 were \$0.10 per MCF, a decrease of 9% compared to \$0.11 per MCF for the corresponding period in the previous year.

Lower transportation expenses in 2009 reflect the Company's ownership in the majority of the pipeline infrastructure at its main producing area of Kaybob, Alberta, where the Company has been increasing its production volumes.

For the second quarter ended June 30, 2009, production expenses of \$1.91 per MCF were 38% higher than \$1.38 per MCF in the corresponding quarter of the previous year. For the six months ended June 30, 2009, production expenses of \$1.67 per MCF were 21% higher than \$1.38 per MCF in the corresponding period of the previous year.

Higher production expenses in 2009 reflect certain one time expenses that were incurred in the second quarter at Kaybob as a result of turnaround operations at the KA Gas Plant where the majority of Celtic's gas is processed.

### **Other Expenses**

For the quarter ended June 30, 2009, general and administrative expenses were \$0.9 million (\$0.87 per BOE), interest expense was \$1.4 million, and depletion, depreciation and accretion expenses were \$19.9 million (\$20.02 per BOE). In the previous year, for the quarter ended June 30, 2008, general and administrative expenses were \$1.0 million (\$1.02 per BOE), interest expense was \$1.6 million, and depletion, depreciation and accretion expenses were \$20.4 million (\$22.70 per BOE).

For the six month period ended June 30, 2009, general and administrative expenses were \$1.9 million (\$0.86 per BOE), interest expense was \$2.3 million, and depletion, depreciation and accretion expenses were \$44.6 million (\$20.43 per BOE). In the previous year, for the six months ended June 30, 2008, general and administrative expenses were \$2.1 million (\$1.10 per BOE), interest expense was \$3.4 million, and depletion, depreciation and accretion expenses were \$40.6 million (\$21.65 per BOE).

Aggregate general and administrative expenses in 2009 were essentially unchanged as the Company has retained similar staffing levels at head office, despite the growth in production year over year. Lower interest expense in 2009 reflects lower market interest rates. Higher depletion, depreciation and accretion expenses reflect higher production volumes; however, per unit costs are lower in 2009 as a result of proved reserve additions at lower than historic costs.

### **Taxes**

For the quarter ended June 30, 2009, Celtic provided for a recovery of future income taxes in the amount of \$2.0 million, compared to a recovery of \$3.6 million in the second quarter of 2008. For the six month period ended June 30, 2009, Celtic provided for a recovery of future income taxes in the amount of \$3.9 million, compared to a recovery of \$6.5 million in the first six months of 2008.

For the six months ended June 30, 2009, Celtic is not required to pay current income taxes as it has sufficient income tax deductions available to shelter taxable income for the period. Estimated income tax deductions available at June 30, 2009 are \$397.3 million and are comprised of \$97.0 million of COGPE, \$156.5 million of CDE, \$31.6 million of CEE, \$106.5 million of UCC and \$5.7 million of share issue costs.

### **Earnings**

Net loss for the quarter ended June 30, 2009 was \$5.5 million (\$0.13 per share, basic and diluted). During the same period, funds from operations were \$20.0 million (\$0.46 per share, basic and diluted). On a barrel of oil equivalent basis, funds from operations in the second quarter of 2009 were \$20.15 per BOE, down 46% from \$37.29 per BOE in the same quarter of 2008.

Net loss for the six months ended June 30, 2009 was \$10.5 million (\$0.25 per share, basic and diluted). During the same period, funds from operations were \$48.1 million (\$1.14 per share, basic and \$1.13 per share, diluted). On a barrel of oil equivalent basis, funds from operations in the first six months of 2009 were \$22.06 per BOE, down 36% from \$34.71 per BOE in the same period of 2008.

The main reason for the decrease in funds from operations per BOE in 2009 was the significantly lower realized natural gas prices received by the Company.

### **Capital Expenditures**

During the quarter ended June 30, 2009, Celtic spent \$36.6 million on capital projects. Drilling and completion operations accounted for \$27.2 million, equipment and facility expenditures were \$7.9 million

and \$1.8 million was spent on land and seismic. Acquisitions were reduced by \$0.3 million as a result of adjustments. In the second quarter of the previous year, capital expenditures were \$67.7 million.

During the six month period ended June 30, 2009, Celtic spent \$78.2 million on capital projects. Drilling and completion operations accounted for \$60.0 million, equipment and facility expenditures were \$15.5 million and \$3.0 million was spent on land and seismic. Proceeds from property dispositions were \$0.3 million. In the corresponding period of the previous year, capital expenditures were \$100.3 million.

At June 30, 2009, the Company had 344,846 (272,000 net) acres of undeveloped land. The Company continues to build on its inventory of prospects for future drilling.

### **Drilling Activity**

During the second quarter of 2009, the Company drilled 9 (8.7 net) wells resulting in 9 (8.7 net) natural gas wells, for an overall success rate of 100%. During the second quarter ended June 30, 2008, Celtic drilled 10 (8.6 net) wells, with an overall success rate of 100%. The average measured depth of net wells drilled in the second quarter of 2009 was 3,665 metres, an increase of 20% compared to the average drilling measured depth of 3,061 metres in the second quarter of 2008.

During the first six months of 2009, the Company drilled 24 (21.4 net) wells resulting in 21 (18.3 net) natural gas wells and 1 (1.0 net) oil wells, for an overall success rate, based on net wells, of 91%. During the six months ended June 30, 2008, Celtic drilled 25 (20.9 net) wells, with an overall success rate of 86%. The average measured depth of net wells drilled in the first six months of 2009 was 2,999 metres, an increase of 6% compared to the average drilling measured depth of 2,820 metres in the first six months of 2008.

### **Source of Funds**

Investment funding for capital expenditures incurred in the second quarter of 2009 was provided by bank debt and cash provided by operating activities.

On June 30, 2009, the Company renewed its syndicated bank credit facility, increasing the authorized borrowing amount by \$15.0 million to \$215.0 million. At June 30, 2009, Celtic had drawn \$154.9 million of its \$215.0 million authorized bank credit facility, leaving sufficient unused credit lines available to fund on-going capital expenditures and working capital deficiencies. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

### **Working Capital**

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At June 30, 2009, the working capital amount, excluding non-cash financial instruments, plus outstanding bank debt represented 73% of the Company's maximum authorized bank borrowing credit limit.

### **Liquidity**

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. With the indications of a continuing global recession in 2009,

oil and gas companies continued to face significant challenges relating to credit availability in 2009. Celtic has good relationships with its syndicate of lenders and recently added two new members to its syndicate, in order to spread the risk. The Company's existing credit facility matures on June 29, 2010.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

### Share Information

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at June 30, 2009, there were 44.2 million common shares outstanding (as at August 5, 2009, there were 44.2 million common shares outstanding). There are no preferred shares outstanding.

As at June 30, 2009, directors, employees and certain consultants have been granted options to purchase 3.1 million common shares of the Company at an average exercise price of \$13.20 per share.

The Company's common shares trade on the TSX under the symbol "CLT".

### Future Commitments – Financial Instruments

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of WTI fixed oil sales price derivative contracts in effect as at June 30, 2009:

Quantity	Remaining term of contract	Fixed price per BBL
2,000 BBLs/day (put-call spread)	July 1 to December 31, 2009	CA\$115.00 (floor) CA\$145.00 (cap)

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at June 30, 2009:

Quantity	Remaining term of contract	Fixed price per MMBTU
30,000 MMBTU/day (swap)	July 1 to December 31, 2009	US\$0.69
40,000 MMBTU/day (swap)	January 1 to December 31, 2010	US\$0.77

The following is a summary of U.S. currency average rate forward swap contracts in effect as at June 30, 2009:

Amount	Remaining term of contract	Fixed exchange rate (CAD/USD)
US\$4,000,000/month	July 1 to December 31, 2009	1.2425
US\$4,000,000/month	January 1 to December 31, 2010	1.2106

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at June 30, 2009:

Amount	Remaining term of contract	Fixed interest rate
CA\$80,000,000	July 1, 2009 to April 22, 2010	3.30%
CA\$20,000,000	July 1, 2009 to April 22, 2010	2.54%
CA\$100,000,000	April 21, 2010 to April 21, 2011	2.07%

## **Advisory Regarding Forward-Looking Statements**

Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

## **Current Economic Environment**

Late in 2008 and early in 2009, the financial community around the world has been rocked with unprecedented losses and business failures. As a result, the current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby cash flow for 2009 has been secured to a certain extent through the use of commodity price, currency and interest rate financial derivative instruments.

Celtic's capital expenditure program for 2009 remains flexible and if the current economic environment continues to deteriorate, the Company has the ability to defer expenditures into the future.

## **2009 Guidance**

Despite the current economic environment, Celtic remains optimistic about its future prospects. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on a historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone potential.

Celtic's Board of Directors previously approved a capital expenditure budget in the amount of \$150 million for 2009. There are no changes to the amount of planned expenditures for 2009 at the time of this report. Capital spending will be financed by funds from operations, available bank credit lines and common share issuances. On April 23, 2009, the Company completed an equity financing by way of a short form prospectus, by issuing 2.75 million common shares at a price of \$13.25 per share, for gross proceeds of \$36.4 million. On June 30, 2009, the Company renewed its syndicated bank credit facility, increasing the authorized borrowing amount by \$15.0 million to \$215.0 million.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2009, estimated decline rates on existing and new volumes and the shut-in of production during the KA Gas Plant turnaround in the second quarter, Celtic expects production in 2009 to average between 13,800 and 14,000 BOE/d (25% oil and 75% gas). This represents between a 25% and 26% increase from the average production of 11,071 BOE/d in 2008. Celtic expects to exit 2009 with production of approximately 16,700 BOE/d.

Financial turmoil and the global recession which have been in the headlines for some time may now be starting to stabilize with expectations of a global economic recovery in 2010. Celtic expects oil prices to be significantly lower in 2009 compared to 2008. Industrial demand for natural gas in North America has also been reduced as a result of the weakening economy, at the same time when natural gas supply in

the United States was increasing. Both these factors have contributed to lower natural gas prices, despite the increased demand for natural gas that was created by a colder than average winter. Celtic also expects much weaker average natural gas prices in 2009 compared to 2008. However, with the rapid decrease in active rigs drilling for gas in North America and with the expected decline of new “flush” natural gas production recently brought on-stream in the United States, the Company is optimistic that natural gas prices may recover towards the end of 2009 or early in 2010.

The Company’s average commodity price assumptions for 2009 is US\$57.00 per barrel for WTI oil (previously US\$53.50 per barrel), US\$4.65 per MMBTU for NYMEX natural gas (previously US\$5.00 per MMBTU), \$4.14 per GJ for AECO natural gas (previously \$4.70 per GJ) and a US/Canadian dollar exchange rate of US\$0.865 (previously US\$0.837). These prices compare to 2008 average prices of US\$99.65 per barrel for WTI oil, US\$8.93 per MMBTU for NYMEX natural gas, \$7.71 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.937.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined under Future Commitments above), funds from operations for 2009 is forecasted to be approximately \$125.0 million or \$2.86 per share (\$2.82 per share, diluted) and net loss is forecasted to be approximately \$7.0 million or \$0.16 per share (\$0.16 per share, diluted). Changes in forecasted commodity prices and variances in production estimates can have a significant impact to estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements shown above.

Bank debt, net of working capital, is estimated to be \$140.0 million by the end of 2009 or approximately 1.1 times forecasted 2009 funds from operations.

Celtic’s capital expenditure budget for 2009 will see the Company participate at high working interests in the drilling of approximately 45 to 50 wells during the year, of which approximately 80% will be horizontal wells. Celtic continues to evaluate and pursue potential property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company’s planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company’s ability to deliver continued per share growth in production, reserves, net asset value, earnings and funds from operations. Given the Company’s strong inventory of drilling locations, we look forward to continued growth in 2009 and beyond.

The information set out herein under the heading “2009 Guidance” is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic’s reasonable expectations as to the anticipated results of its proposed business activities for 2009. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

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