

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis

The following Management's Discussion and Analysis ("MD&A") for Second Wave Petroleum Inc. ("Second Wave" or the "Company") should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2009 and December 31, 2008. This MD&A incorporates information up to and including April 29, 2010. The financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). All of the amounts reported in this MD&A are in Canadian dollars, unless otherwise indicated. Certain other information with respect to the Company is available on SEDAR at www.sedar.com and at the Company's website at www.secondwavepetroleum.com. Information can also be obtained by contacting the Company at Second Wave Petroleum Inc, Suite 1700, 520, 5th Ave. S.W., Calgary, Alberta, T2P 3R7.

NON-GAAP FINANCIAL MEASUREMENTS

The Company has used certain measures of financial reporting that are commonly used benchmarks within the oil and gas industry in this MD&A that are considered non-GAAP measures. The measures used in this document include "funds from operations", "funds from operations per share", and "operating netback". The term funds from operations contained within the MD&A should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with GAAP. The Company believes that funds from operations is a useful supplementary measure as investors may use this information to analyze operating performance, leverage and liquidity. Funds from operations, as disclosed within this MD&A, represents cash flow from operating activities before changes in non-cash working capital. The Company presents funds from operations per share whereby per share amounts are calculated consistent with the calculation of net loss and comprehensive loss per share. The Company believes that the term operating netback contained within the MD&A is also a useful supplementary measure as investors may use this information to analyze field level operating performance of the Company's oil and gas properties. Further supplemental indicators of performance common to the oil and gas industry are the measurement of costs and expenses on a per barrel of oil equivalent (boe). These non-GAAP measures may not necessarily be comparable to similarly titled measures used by other entities and readers of this MD&A are cautioned in attempting to make such comparisons.

OTHER MEASUREMENTS

For the purposes of calculating unit costs, natural gas has been converted to a barrel of oil equivalent ("BOE") using 6,000 cubic feet (6 Mcf) of natural gas equal to one barrel of oil (6:1), unless otherwise stated. The BOE conversion ratio of 6 Mcf to 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Therefore BOEs may be misleading if used in isolation. References to natural gas liquids ("NGLs") in this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (BOE).

ADVISORY REGARDING FORWARD LOOKING STATEMENTS

Certain statements included or incorporated by reference in the MD&A constitute forward-looking statements or forward-looking information under applicable securities legislation. Forward-looking statements or information typically contain statements with words such as "anticipate", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to reserves, crude oil and natural gas prices, well productivity, operating costs, general and administrative costs, taxation rates, interest rates, and capital expenditure plans for 2010 and beyond.

Existing or potential investors should not place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations they are based on will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown, risks and uncertainties, both general and specific that contributes to the possibility that although the predictions, forecasts, projections and other forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in the presentation include general economics, business and market conditions; volatility of energy prices; fluctuations in interest rates; energy supply and demand; competition, access to future funding,

timing and amount of capital expenditures, imprecision in estimated future productive capacity, well productivity, operating cost adjustments; cost overruns; and such other risks and uncertainties described from time to time. Existing or potential investors are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date this report. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Examples of forward-looking information included in this document include, but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions which may prove to be incorrect:

- The expected increase in the 2010 commodity production rates and related expected downward trend in operating costs and G&A expenses on a per boe basis over the next couple of quarters as a result of the first quarter 2010 capital program; this is subject to the risk and uncertainty that actual 2010 production rates, and related new well operating costs may differ materially from what is currently anticipated.
- The expected increase in operating netbacks per boe in 2010 as a result of actual improved pricing for crude oil to date, and current future strip pricing for crude oil for the rest of the year. Further expected lower operating costs per boe as outlined above is expected to contribute to a higher operating netback. This is subject to the risk and uncertainty that oil pricing will remain strong during 2010, and not differ materially from what is currently anticipated.

This MD&A is dated as at April 29, 2010.

Abbreviations

<i>Crude oil and natural gas liquids</i>		<i>Natural gas and natural gas liquids</i>	
<i>bbl</i>	<i>barrel</i>	<i>mcf</i>	<i>thousand cubic feet</i>
<i>boe</i>	<i>barrel of oil equivalent</i>	<i>mcf/d</i>	<i>thousand cubic feet per day</i>
<i>bbl/d</i>	<i>barrels per day</i>	<i>gj</i>	<i>gigajoule</i>
<i>boe/d</i>	<i>barrels of oil equivalent per day</i>	<i>NGL</i>	<i>natural gas liquids</i>
<i>WTI</i>	<i>West Texas intermediate</i>		

Overview

	Three months ended			Year ended		
	December 31,			December 31,		
	%			%		
(\$000s, except share amounts)	2009	2008	Change	2009	2008	Change
Petroleum and natural gas sales	4,522	4,688	(4)	15,651	21,618	(28)
Royalties	(662)	(560)	18	(1,758)	(2,801)	(37)
Lease operating costs	(2,081)	(2,468)	(16)	(8,622)	(7,443)	16
Transportation	(86)	(163)	(47)	(389)	(384)	1
Operating netback⁽¹⁾	1,693	1,497	13	4,882	10,990	(56)
Other income	208	-	-	208	-	-
Realized gain (loss) on financial derivatives	(319)	12	2,758	(609)	(361)	69
General and administrative	(614)	(478)	28	(2,300)	(2,529)	(9)
Financing expenses	(213)	123	273	(1,145)	(356)	222
Amortization of loan commitment fees	47	65	(28)	228	65	251
Asset retirement expenditures	-	(85)	-	(38)	(213)	(82)
Funds from operations⁽²⁾	802	1,134	(25)	1,226	7,596	(84)
Unrealized gain (loss) on financial derivatives	90	22	309	(444)	-	-
Depletion, depreciation and accretion	(2,750)	(2,499)	10	(9,904)	(6,809)	45
Future income taxes	3,673	-	-	4,066	-	-
Accretion of convertible debenture	(18)	-	-	(36)	(13)	176
Stock-based compensation	(420)	(264)	59	(1,300)	(1,214)	7
Amortization of loan commitment fees	(47)	(65)	-	(228)	(65)	251
Asset retirement expenditures	-	85	-	38	213	(82)
Net income (loss) before non-controlling interest	1,329	(1,587)	184	(6,582)	(292)	(2,154)
Non-controlling interest	-	-	-	-	47	-
Net income (loss) and comprehensive income (loss)	1,329	(1,587)	184	(6,582)	(246)	(2,576)
Funds from operations per share ⁽¹⁾						
Basic (\$)	0.01	0.04	(75)	0.03	0.27	(89)
Diluted (\$)	0.01	0.04	(75)	0.03	0.27	(89)
Cash flow from operating activities per share:						
Basic (\$)	0.01	0.08	(88)	0.03	0.20	(85)
Diluted (\$)	0.01	0.08	(88)	0.03	0.20	(85)
Net income (loss) and comprehensive income (loss) per share:						
Basic (\$)	0.02	(0.05)	140	(0.15)	(0.01)	(1,400)
Diluted (\$)	0.02	(0.05)	140	(0.15)	(0.01)	(1,400)
Average number of shares outstanding (000s):						
Basic	57,710	31,089	86	44,152	28,557	55
Diluted	59,000	31,089	90	44,152	28,557	55

(1) Operating netback is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. We consider it an important measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.

(2) Funds from operations and funds from operations per share are non-GAAP measures that do not have a standardized meaning as prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by other oil and gas companies. We consider them to be important measure which demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.

As of the reporting date of April 29, 2010, Second Wave had 70,779,924 shares outstanding.

	Three months ended December 31,			Year ended December 31,		
	2009	2008	% Change	2009	2008	% Change
(\$000s)						
Cash flow from operating activities (GAAP)	507	2,510	(79)	1,381	5,844	(76)
Change in non-cash working capital (GAAP)	295	(1,376)	121	(154)	1,752	(1,088)
Funds from operations (non-GAAP)	802	1,134	(25)	1,226	7,596	(84)

Funds from Operations, Cash flow from operating activities, and Net Income (Loss) and Comprehensive Net Income (Loss)

<i>(\$000s, except per share)</i>	Three months ended			Year ended		
	2009	2008	December 31, %	2009	2008	December 31, %
Funds from operations⁽¹⁾	802	1,134	(29)	1,226	7,596	(84)
Per share:						
Basic (\$)	0.01	0.04	(75)	0.03	0.27	(89)
Diluted (\$)	0.01	0.04	(75)	0.03	0.25	(88)
Cash flow from operating activities	507	2,510	(79)	1,381	5,844	(76)
Per share:						
Basic (\$)	0.01	0.08	(88)	0.03	0.20	(85)
Diluted (\$)	0.01	0.08	(88)	0.03	0.19	(84)

(1) Funds from operations is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers it an important measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

Funds from operations and cash flow from operating activities for the three months ended December 31, 2009 decreased as compared with the same period in 2008. The decrease in funds from operations is due to higher financing costs, and a larger realized loss on financial derivatives, partly offset by lower operating cost in the quarter.

Funds from operations and cash flow from operating activities for the year ended December 31, 2009 also decreased significantly from 2008 levels. This decrease is primarily due to the impact of lower commodity prices on our operations when compared to the prior period.

<i>(\$000s, except per share)</i>	Three months ended			Year ended		
	2009	2008	December 31, %	2009	2008	December 31, %
Net income (loss) and comprehensive income (loss)	1,329	(1,587)	184	(6,582)	(246)	(2,576)
Per share:						
Basic (\$)	0.02	(0.05)	140	(0.15)	(0.01)	(1,400)
Diluted (\$)	0.02	(0.05)	140	(0.15)	(0.01)	(1,400)

Net income and comprehensive income for the three month period ended December 31, 2009 was \$1,329,000 or \$0.02 per share compared to a net loss and comprehensive loss of (\$1,587,000), or (\$0.05) per share, for the same period in 2008.

For the year ended December 31, 2009, net loss and comprehensive loss was (\$6,582,000) or (\$0.15) per share, compared to the net loss and comprehensive loss for the comparable period in 2008 of (\$246,000) or (\$0.01) per share. Almost all metrics were lower during 2009 as compared with 2008, driven mainly by the impact of lower commodity pricing received during 2009.

Petroleum and natural gas sales

Sales volumes		Three months ended			Year ended		
		2009	2008	Change	2009	2008	Change
				%			%
Crude oil	<i>bbl/d</i>	498	546	(8)	504	450	12
Natural gas liquids	<i>bbl/d</i>	50	44	14	44	35	26
Natural gas	<i>mcf/d</i>	2,765	2,711	2	2,650	2,000	33
Combined (6:1)	<i>boe/d</i>	1,009	1,042	(3)	990	819	21
Commodity weighting (%)							
Oil and liquids		54	56	(3)	55	59	(7)
Natural gas		46	44	5	45	41	10
Total		100	100	-	100	100	-

Sales volumes averaged 1,009 boe/d during the fourth quarter of 2009, down marginally from 1,042 boe/d average in the fourth quarter of 2008.

The Company shut-in approximately 160 boe/d in early 2009 due to low commodity prices in combination with high processing costs from non-owned facilities. This production is currently shut-in and is expected to remain shut-in until the operating environment improves. The Company has adjusted its reserve bookings and budgets to reflect the uncertainty on this timing.

For the year ended in 2009, sales volumes averaged 990 boe/d, an increase of 21% from the 819 boe/d achieved in the comparable period of 2008.

The Company continues to have a greater percentage of production derived from oil as opposed to natural gas. Given the current low commodity price environment for natural gas, the Company expects to continue to target oil weighted prospects. Notwithstanding all of the Company's oil prospects produce associated solution gas, the Company's oil weighting is expected to gradually increase from 54% to 63% during 2010.

Although fourth quarter 2009 average volumes were not materially different than that of the comparative period average, the Company embarked on a significant capital program during the fourth quarter of 2009, continuing into 2010. The Company drilled, completed and brought on production 2 (2.0 net) horizontal and 1 (1.0 net) vertical oil wells and re-drilled 1 horizontal well in Judy Creek late in the fourth quarter. Production from these wells averaged 129 boe/d for the quarter and 224 boe/d in December. January 2010 production from these three wells is estimated to average 304 boe/d.

The Company drilled 9 (8.4 net) wells, comprised of 7.0 (6.4 net) horizontal and 2 (2.0 net) vertical wells, with 6 (6.0 net) horizontal and 2 (2.0 net) vertical wells being drilled at Judy Creek. As at March 31, 2010, 4 (4.0 net) of the 9 (8.4 net) wells have been completed, equipped and have been tied-in for production to Company owned facilities, with the remaining 5 (4.4 net) wells brought on stream during the first week of April 2010. In addition to an active capital program in the first quarter the Company also disposed of 130 boe/d of non-core production on January 11, 2010.

Irrespective of the timing of new production additions, and non-core dispositions, we expect that the first quarter of 2010 average rate will be higher than the fourth quarter average for 2009, based on completion activities that have taken place in April 2010. Management is expecting a substantial increase in the second quarter 2010 average rate as compared with the 2009 exit production rate.

Revenues (\$000s)	Three months ended			Year ended		
	2009	2008	Change	2009	2008	Change
			%			%
Crude oil	3,169	2,729	16	11,014	14,628	(25)
Natural gas liquids	254	194	31	772	946	(18)
Natural gas	1,099	1,765	(38)	3,865	6,044	(36)
Total oil and gas	4,522	4,688	(4)	15,651	21,618	(28)

Second Wave's petroleum and natural gas ("P&NG") sales may vary significantly from period-to-period as a result of changes in commodity pricing and or sales volumes. The Company takes approximately 95% of its working interest production "in-kind" and it is marketed and sold through various commodity purchasers. Crude oil is marketed under various short term evergreen contracts with major North American Companies and/or marketers. Natural gas sales are also marketed under a short term contract and sold under both "spot" and monthly contracts with a major North American Company.

Gross revenues from P&NG sales in the fourth quarter of 2009 totaled \$4,522,000, down by 4% from the same period last year. Revenues in the comparative periods were impacted by a significantly lower natural gas price, a nominal decrease in production volumes which were partially offset by improved oil pricing resulting in lower overall gross revenues.

For the year, P&NG sales revenues were \$15,651,000, a decrease of 28% from the \$21,618,000 received in the comparable period of 2008. Although average sales volumes were higher in 2009 the significant decrease in gross revenues in the period were primarily driven by a 40% drop, per boe, in realized commodity pricing from the comparative 2008 period.

Financial derivatives

The Company does not enter into financial derivative contracts of a speculative nature. The Company will from time to time enter into financial derivative contracts to mitigate commodity price risk as a measure to protect its cash flow. During 2009, the Company entered into certain fixed price crude oil and natural gas contracts. As at December 31, 2009, the summary of contracts and their respective remaining fair market values based on third party estimates are as follows:

Daily quantity	Term of contract	Price	Fair market value at December 31, 2009 (liability)/asset
Oil (bbls)		Fixed per bbl (WTI)	
300	January 1, 2009 – March 31, 2010	CDN\$71.85	\$ (340,227)
200	January 1, 2010 – March 31, 2010	CDN\$82.90	(28,179)
500	April 1, 2010 – June 30, 2010	CDN\$85.15	(46,230)
300	July 1, 2010 – September 30, 2010	CDN\$86.90	(18,339)
			\$ (432,975)
Gas (GJs)		Fixed per GJ (AECO Monthly)	
1,200	November 1, 2009 – March 31, 2010	CDN\$5.16	\$ (22,856)
600	April 1, 2010 – October 31, 2010	CDN\$5.42	11,649
1,800			\$ (11,207)
		Total	\$ (444,182)

In addition, on January 22, 2010, the Company entered into the following fixed price crude oil and natural gas contracts:

Daily quantity	Term of contract	Price
Gas (GJs)		Fixed per GJ (AECO Monthly)
1,200	April 1, 2010 – June 30, 2010	CDN\$5.36
1,200	July 1, 2010 – September 30, 2010	CDN\$5.46

Commodity pricing experienced since entering into the contracts has been volatile. Oil pricing has strengthened, and has continued to improve into 2010. Natural gas pricing strengthened late in 2009, but has since dropped considerably. During the fourth quarter of 2009, the Company recorded \$90,000 (2008 - \$22,000) of unrealized gains and \$319,000 (2008 - \$22,000 gain) of realized losses as a result of these contracts. During the year ended December 31, 2009, the Company recorded \$444,000 (2008 – \$nil) of unrealized losses, and \$609,000 (2008 – \$361,000) of realized losses as the result of those contracts.

Average Sales Prices ⁽¹⁾		Three months ended			Year ended		
		December 31,		%	December 31,		%
		2009	2008	Change	2009	2008	Change
Oil	<i>\$/bbl</i>	69.08	54.28	27	59.86	88.81	(32)
Natural gas liquids	<i>\$/bbl</i>	55.76	48.35	15	48.51	72.99	(34)
Natural gas	<i>\$/mcf</i>	4.32	7.08	(39)	4.00	8.25	(52)
Combined (6:1)	<i>\$/boe</i>	48.71	48.90	-	43.34	72.13	(40)

(1) Average sales prices do not include the impact of hedging activities

Benchmark Pricing	Three months ended			Year ended		
	December 31,		%	December 31,		%
	2009	2008	Change	2009	2008	Change
WTI crude oil (<i>US\$/bbl</i>)	76.19	58.80	30	61.80	99.67	(38)
WTI crude oil (<i>Cdn\$/bbl</i>)	80.48	71.15	13	70.54	105.62	(33)
AECO natural gas (<i>Cdn\$/mcf</i>) ⁽¹⁾	4.50	6.69	(33)	3.95	8.13	(51)
Exchange rate (<i>US\$/Cdn\$</i>)	1.06	1.21	(12)	1.14	1.07	7

(1) The AECO natural gas price reported is the average daily spot price

The overall average price per boe received from sale of oil and gas products in the fourth quarter of 2009 was consistent with pricing received during the fourth quarter last year.

During the third quarter of 2008 world oil prices and spot prices for natural gas commenced a steep decline and remained at low levels during most of 2009. The pricing that the Company receives from the sale of its commodities are outside the control of the Company (see discussion of financial derivative contracts above). As a result the average price received year over year was down by 40%. During the first quarter of 2010 oil prices have strengthened considerably, however natural gas pricing is weak. Consistent with 2009, Second Wave's continues to focus its capital expenditures on oil prospects.

Royalties

(\$000s)	Three months ended			Year ended		
		December 31,		December 31,		
	2009	2008	Change	2009	2008	Change
Crown royalties	195	233	(16)	560	1,448	(61)
Freehold	407	269	51	1,032	1,083	(5)
Gross overriding	60	58	3	166	270	(39)
Total	662	560	18	1,758	2,801	(37)
Per boe ⁽¹⁾	7.13	5.84	22	4.87	9.35	(48)
As % of oil and gas revenues	15%	12%	25	11%	13%	(15)

(1) Royalties per boe is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it provides supplemental disclosure of the Company's performance on one of its important costs.

Total royalties increased in the fourth quarter of 2009, totaling \$662,000 versus \$560,000 in the same period of 2008. Royalties as a percentage of revenues amounted to 15% during the fourth quarter of 2009, compared to 12% during the same quarter last year. The increase in total royalties, royalty rate percentages and per boe amounts in the fourth quarter of 2009 was due to a re-allocation of certain volumes in the Provost area to a higher royalty rate freehold well from the crown wells in the area. Overall volumes and product revenue were not affected by the re-allocation.

Total royalties for the year ended December 31, 2009 are down 37% compared to 2008, mainly due to lower commodity prices received in 2009. Royalties as a percentage of oil and gas revenues were down slightly year-over-year due mainly to new production volumes from capital expenditure programs having lower royalty rates.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "NRF") containing the government's proposals for Alberta's new royalty regime, which became the foundation for the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF and applicable new legislation became effective on January 1, 2009, and establishes new increased royalty rates for petroleum and natural gas in Alberta.

Implementation of the NRF had a negligible impact on Second Wave's existing production due to low levels of commodity pricing and individual low well productivity.

In response to a drop in commodity prices, and lower industry activity, on November 19, 2008, the Alberta government introduced a new 5 year transitional royalty regime with the objective of promoting the drilling of new wells. Under this program companies drilling new oil and natural gas wells (between 1,000 and 3,500 meters deep) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates until January 1, 2014 (at which time the royalties revert to the NRF) or those outlined in the NRF. Wells qualifying for this program must be drilled during the period commencing on November 19, 2008 until December 31, 2013.

On March 3, 2009, the Alberta government announced a three-point incentive program to encourage additional activity in the oil and gas sector, of which only the first two aspects are relevant to oil and gas producers; i) drilling royalty credit, ii) new well incentive program, and iii) reclamation and abandonment program for old well sites. A drilling royalty credit will offer \$200 in royalty credits per meter drilled on new conventional oil and natural gas wells spud and rig released between April 1, 2009 and April 1, 2010. The new well incentive program reduced the royalty to a maximum 5% rate on any wellbore that has not produced between January 1 and April 1, 2009 for the period of the earlier of: i) the production of 50,000 barrels of oil production, ii) 500 million cubic feet (MMcfe) of gas production, or iii) 12 calendar months. Once this incentive expires, royalties will be based on either the transitional royalty rates or the NRF rates, as applicable.

On March 11, 2010, the Alberta Government announced that it will make additional modifications to the province's Crown Royalty framework. The Alberta Government sponsored Competitiveness Review recommended various items to be implemented, with the final changes to be confirmed and announced by May 31, 2010.

The proposed changes include:

- The current maximum five percent royalty rate for the first twelve months of production up to a maximum of 50,000 bbls of oil or 500,000 mcf of natural gas is proposed to become a permanent incentive. This incentive is currently scheduled to end on March 31, 2011.

- The maximum royalty rate for crude oil wells is proposed to be reduced to 40% from the current 50% rate. The change is proposed to become effective January 1, 2011.
- The maximum royalty rate for natural gas wells is proposed to be reduced to 36% from the current 50% rate. The change is proposed to become effective January 1, 2011.
- Effective January 1, 2011, no Alberta drilled wells will be allowed to select the transitional royalty program.

The Company drilled 8 gross (7.25 net) wells in Alberta during 2009, all of which were successful and all of which did not commence production until subsequent to April 1, 2009. As a result, the Company expects to benefit from the 5% royalty rate on these wells. The Company elected these wells to qualify for the transitional royalty regime.

Of the 8 wells drilled in Alberta, 5 gross (4.25 net) were drilled subsequent to April 1, 2009 and are eligible for both the 5% crown royalty rate and the drilling incentive credit. At December 31, 2009, the Company estimates that it earned \$2,195,000 in drilling incentive credits and estimate that the 9 gross (8.625 net) wells drilled in Alberta in Q1 2010 earned an additional \$4,192,000 of drilling credits. In 2009 the company utilized \$170,000 of the drilling credits earned. At this time the Company is not able to fully utilize the drilling incentive credits as the amount of crown royalty payments are currently not sufficient to draw against the amount of drilling credits from the program. The Company will continue to explore its options to utilize the incentive credits through the crown program.

Lease Operating Costs

Lease operating costs include all costs relating to the operation of producing crude oil and natural gas properties. Typical costs include: contract labor, chemicals and supplies, repairs and maintenance, utilities, and gathering and processing fees. Work-overs performed on producing wells are also considered to be operating costs, in situations where there are no enhancements to the equipment and related operations. Work-overs would typically include bottom-hole pump replacement, down-hole sand clean-outs, and replacement or repair of other worn equipment. As the majority of Second Wave's wells are oil wells, work-overs are a material component of operating costs. This is in contrast to certain of the Company's competitors that are mainly natural gas producers, whose work-over costs would be less frequent due to an absence of down-hole moving parts.

<i>(\$000s, except per boe)</i>	Three months ended			Year ended		
	2009	2008	Change %	2009	2008	Change %
Lease operating costs	2,081	2,468	(16)	8,622	7,443	16
Per boe (\$) ⁽¹⁾	22.41	25.75	(13)	23.87	24.84	(4)

(1) Lease operating cost per boe is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it provides supplemental disclosure of the Company's performance on one of its important costs.

Total lease operating costs decreased 16% from \$2,468,000 in the fourth quarter of last year to \$2,081,000 in 2009, and on a quarter-over-quarter basis operating costs reduced by 8% from \$2,224,000 in the third quarter of 2009. On a boe basis, total operating costs decreased 13% in the three months ended December 31, 2009 to \$22.41/boe from \$25.75/boe in the same period of 2008. On a quarter-over-quarter basis operating cost decreased by 8% from \$24.42/boe during the third quarter in 2009 to \$22.41/boe in the fourth quarter. Reductions in aggregate and on a per boe basis are primarily due to the success of the Company's optimization programs.

Even though a material reduction in costs occurred on a year-over-year basis, the operating expenses in the quarter were adversely impacted by the Company's Judy Creek and Battle Creek fields. In 2009, these fields accounted for 28% of the Company's total operating costs while contributing only 18% of the production. During 2009 both of these fields were burdened with high fixed costs at processing facilities that were underutilized. However, since the second half of 2009 a significant portion of the Company's capital has been focused in Judy Creek with 3 (3.0 net) wells drilled, and an additional 8 (8.0 net) wells drilled in the area during the first quarter of 2010. Expected continued successful development of the Judy Creek area, with up to an additional 15 wells to be drilled in 2010, will provide additional production, and should result in a downward trend in lease operating costs.

During the first quarter of 2010, the Company started a pilot CO2 flood in its Battle Creek area, and as a result expects area operating costs to be high in 2010. However, based on successful drilling activities to date in Judy Creek, the Company expects that corporate operating costs will continue to trend downwards over the next couple of quarters.

For year ended December 31, 2009, aggregate lease operating costs increased by 16% from the comparable period of 2008. On an annual per boe basis, lease operating costs were slightly lower with those experienced in 2008.

Quarterly Lease Operating Cost Summary

	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operating expenses	2,081	2,224	2,356	1,962	2,468	2,588	1,558	829
Per boe	22.41	24.42	26.24	22.43	25.75	30.13	21.88	18.07

The Company took control of the assets of Milagro Energy Inc. on May 8, 2008. When acquired, Milagro's properties had high operating costs and were undercapitalized. To restore these assets to acceptable operating standards, Second Wave invested funds on repairs and maintenance activities, thereby incurring costs on a total dollar and boe basis commencing in the second quarter of 2008. Through optimizations, realized operating efficiencies and the shutting-in of higher operating costs wells, the Company has achieved improvements on a cost per boe basis. With the continued development of the Judy Creek area these costs are expected to continue to improve on per boe basis as greater efficiencies are maintained and fixed costs are allocated over a larger production base.

Transportation

(\$000s, except per boe)	Three months ended December 31, %			Year ended December 31, %		
	2009	2008	Change	2009	2008	Change
Transportation	86	163	(47)	389	384	1
Per boe (\$) ⁽¹⁾	0.93	1.70	(45)	1.08	1.28	(16)

(1) Transportation costs per boe is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it provides supplemental disclosure of the Company's performance on one of its costs.

The Company incurs transportation costs for the crude oil and natural gas it produces once the commodity enters a feeder or main pipeline to the title transfer point. Transportation costs for the quarter and year ended December 31, 2009 have decreased when compared with 2008 on a per boe basis due as a result shutting in high transportation cost wells.

Operating Netback

Operating netback is the amount of directly attributable net cash flow derived from field operations of the Company's crude oil and natural gas wells. The table below displays the operating netback on a per boe basis.

(\$/boe)	Three months ended December 31, %			Year ended December 31, %		
	2009	2008	Change	2009	2008	Change
Petroleum and natural gas sales	48.71	48.90	-	43.34	73.12	(41)
Royalties	(7.13)	(5.84)	22	(4.87)	(9.35)	(48)
Lease operating costs	(22.41)	(25.75)	(13)	(23.87)	(24.84)	(4)
Transportation	(0.93)	(1.70)	(45)	(1.08)	(1.28)	(16)
Operating netback ⁽¹⁾	18.24	15.61	17	13.52	37.65	(64)

(1) Operating netback is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

Operating netback improved during the fourth quarter of 2009 as compared with 2008, mainly due to lower operating costs in the current quarter. On a quarter-over-quarter basis operating netbacks improved by 24% from \$14.74/boe in the third quarter of 2009 to \$18.24/boe in the fourth quarter. Operating netback was significantly lower for year ended December 31, 2009, when compared to the prior year, due mainly to the decrease in average commodity prices.

Management expects operating netbacks to further improve during the first quarter of 2010, due mainly from the combination of improving crude oil prices during the quarter and lower unit operating costs per boe driven by increased production volumes at Judy Creek. In combination with the Company's capital program, should crude oil prices remain strong, we anticipate that operating netbacks will trend higher throughout the year.

General and Administrative ("G&A")

<i>(\$000s, except per boe)</i>	Three months ended			Year ended		
	2009	2008	December 31, %	2009	2008	December 31, %
			Change			Change
G&A expenses	753	778	(3)	2,918	3,193	(9)
Capitalized G&A expenses	(139)	(301)	(54)	(618)	(664)	(7)
Net G&A expenses	614	477	29	2,300	2,529	(9)
Per boe (\$) ⁽¹⁾	6.62	4.02	65	6.37	7.76	(18)

(1) G&A per boe is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it provides supplemental disclosure of the Company's performance on one of its important costs.

General and administrative expenses, net of capitalized G&A, increased 29% in the fourth quarter of 2009, to \$614,000 from \$477,000 in the same period last year. On a quarter-over-quarter basis, G&A increased by 23% from \$500,000 in the third quarter of 2009 to \$614,000 in the fourth quarter. This quarter-over-quarter increase was associated with \$125,000 of costs related to our annual financial audit and reserve report requirements.

On a per boe basis, general and administrative expenses, net of capitalized G&A, were 65% higher in the comparative quarter. Both aggregate and per boe G&A increased in the fourth quarter of 2009 as compared with 2008 primarily due to an adjustment in the fourth quarter of 2008 to the capitalized portion of G&A.

General and administrative expenses of \$139,000 were capitalized during the fourth quarter of 2009 compared with \$301,000 in the comparative period of 2008.

For the year ended December 31, 2009, general and administrative expenses, net of capitalized G&A, decreased 9% from those of the comparative period, however on a per boe basis the decrease was 18%.

As the Company is planning additional capital expenditures during 2010, management expects to add additional employees in 2010 which would increase the aggregate amount of G&A costs. Nevertheless management expects that G&A per boe will trend downwards in 2010, as a result of increased production volumes from successful drilling operations.

Stock-Based Compensation

Stock-based compensation expense, net of capitalized stock-based compensation, for the three months ended December 31, 2009 was \$556,000, as compared to \$264,000 in the comparative period of 2008. The increase in stock-based compensation expense is due to the timing of stock option grants, and the amounts capitalized in each period. Stock-based compensation expenses of \$136,000 were capitalized during the quarter, as compared with \$257,000 capitalized in the comparative 2008 quarter.

For the year ended December 31, 2009 and 2008, stock-based compensation expense, net of capitalized stock-based compensation, was \$1,300,000 and \$1,214,000 respectively. Stock-based compensation expenses of \$618,000 and \$661,000 were capitalized during the year ended December 31, 2009 and 2008 respectively.

Financing Expenses

(\$000s, except per boe)	Three months ended			Year ended		
	2009	2008	December 31, %	2009	2008	December 31, %
Interest on current portion of debt	133	113	18	832	327	154
Interest on convertible debenture	81	-	-	161	31	419
Interest on long term portion of debt	-	147	-	152	381	(60)
Finance charges on flow through share obligations	-	(383)	-	-	(383)	-
Total financing expenses	214	(123)	276	1,145	356	222
Per boe (\$)	2.31	(1.28)	80	3.17	1.19	166

Financing expenses increased by 276% to \$214,000 in the fourth quarter of 2009 when compared to the same period in 2008, mainly as a result of a recovery of finance charges relating to flow through obligations in the 2008 comparative period.

Given the global credit crisis and the higher borrowing costs charged by lenders, the Company's borrowing costs increased significantly in 2009. Although the bank's prime lending rate is currently 2.25%, down from approximately 5.25% at this time last year, the increase in rate premiums has offset the drop in prime interest rates. The Company's 2009 average debt levels increased from 2008, which has also contributed to the increase in financing costs.

For the year ended December 31, 2009, financing expenses increased by 222% to \$1,145,000 as compared with \$356,000 in 2008.

Depletion, Depreciation and Accretion

Depletion and depreciation rates are a useful measure for evaluating finding and development costs on proved reserves as the rate generally considers all incurred acquisition, exploration and development capital costs in addition to future development costs associated with proved non-producing reserves. A limitation with the calculation is that it does not immediately include probable reserves captured from ongoing, successful capital expenditures, similar to those that occurred during the first quarter of 2010 with the Company's development of its Judy Creek oil resource play.

(\$000s, except per boe)	Three months ended			Year ended		
	2009	2008	December 31, %	2009	2008	December 31, %
Depletion	2,613	2,339	12	9,382	6,392	47
Depreciation	4	6	(33)	15	19	(21)
Accretion of asset retirement obligations	132	154	(14)	507	398	27
Total	2,749	2,499	10	9,904	6,809	45
Per boe (\$) ⁽¹⁾	29.61	26.07	14	27.42	22.72	21

- (1) Depletion, depreciation and accretion per boe is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. Management considers it an important measure as it provides supplemental disclosure of the Company's performance on one of its important non cash costs.

Depletion, depreciation and accretion expense increased 10% in the fourth quarter of 2009 to \$2,749,000 from \$2,499,000 in the same period of 2008. This increase in absolute dollar amount is a result of expenditures incurred from Second Wave's exploration and development program. A total of \$6,595,000 was incurred on facilities to expand and upgrade facilities during 2009. These expenditures were required for the anticipated increases in production throughputs from the Company's capital program. Although management expects additional pipeline tie-ins and facility work will be required in 2010 and beyond, the impact should be lower on depletion in future periods.

Depletion, depreciation and accretion expense increased 45% in the year ended December 31, 2009 to \$9,903,000 from \$6,809,000 in the same period of 2008, for the same reasons discussed above.

Accretion of Convertible Debenture

Accretion of convertible debenture was \$36,000 during the year ended December 31, 2009 and \$13,000 during the comparative period in 2008.

Income Taxes

The future income tax recovery for the three months ended December 31, 2009 was \$3,673,000, compared to \$Nil in the comparative period of 2008.

The future income tax recovery for the year ended December 31, 2009 was \$4,066,000, compared to \$Nil in the comparative period of 2008.

During the fourth quarter of 2009 and first quarter of 2010, Second Wave renounced \$3,980,000 and \$8,996,000 of qualifying expenditures to its flow-through subscribers from its February, June, and October 2009 flow through equity financings. As a result of these renouncements the Company recorded an income tax recovery of approximately \$4,066,000 during 2009.

Income taxes are comprised of two components: current and future income taxes. The expected 2009 income tax rate as a percentage of pre-tax income is 29.14%.

Capital Expenditures

During the quarter ended December 31, 2009, \$13,373,000 was incurred on capital expenditures as compared with \$7,256,000 in the comparative quarter in 2008. For the year ended December 31, 2009, \$24,114,000 was expended on capital additions as compared with \$21,656,000 during the 2008 comparative as summarized below:

Capital Expenditures (\$000s)	Three months ended			Year ended		
	2009	2008	Change	2009	2008	Change
			%			%
Land and acquisitions	835	1,567	(47)	1,224	5,447	(78)
Geological and geophysical	1,004	915	10	1,096	1,130	(3)
Drilling and completion	7,281	458	1,490	14,756	7,326	101
Facilities and equipment	4,106	4,015	(2)	6,595	7,089	(7)
Dispositions	-	-	-	(182)	-	-
Other	7	-	-	7	-	-
Capitalized G&A	140	301	(53)	618	664	(7)
Total cash portion	13,373	7,256	84	24,114	21,656	11
Non-cash portion						
Corporate acquisition	-	-	-	-	26,265	-
Capitalized stock-based compensation	136	257	(47)	385	661	(42)
Asset retirement obligations additions from drilling and acquisitions	78	77	1	530	139	281
Asset retirement obligations reductions from property sales	-	-	-	(52)	-	-
Total non-cash	214	334	(36)	863	27,065	(97)
Total capital expenditures	13,587	7,590	79	24,977	48,721	(49)

Drilling results (2009)	Three months ended December 31, 2009			Year ended December 31, 2009		
			Working interest			Working interest
	Gross	Net	%	Gross	Net	%
Crude oil wells	6	5.25	87.5	10	9.25	92.5
Natural gas wells	-	-	-	-	-	-
Dry and abandoned	-	-	-	-	-	-
Total wells	6	5.25	87.5	10	9.25	92.5

Drilling results (2008)	Three months ended December 31, 2008			Year ended December 31, 2008		
			Working interest			Working interest
	Gross	Net	%	Gross	Net	%
Crude oil wells	1	1.0	100	7	6.045	86
Natural gas wells	-	-	-	-	-	-
Dry and abandoned	-	-	-	3	2.65	88
Total wells	1	1.0	100	10	8.695	87

The increase in capital expenditures in the three months ended December 31, 2009 was the result of a more significant drilling program in the fourth quarter of 2009 which including the drilling of 6 gross (5.25 net) wells all of which targeted oil at a 100% success rate, as compared to drilling only 1 (1.0 net) well in the 2008 comparative quarter.

For the year ended December 31, 2009, Second Wave has drilled 10 gross (9.25 net) wells, all of which were targeting oil for a 100% success rate, as compared with 10 gross (8.695 net) wells in the 2008 comparative period.

Liquidity and Capital Resources

The oil and gas business is inherently risky and capital intensive and can require significant capital and cash resources to expand by growing reserves, production and cashflow. As at December 31, 2009, the Company had a working capital deficiency of \$12,027,000, had drawn \$4,258,000 of its available \$20,000,000 in debt facilities, and for the year ended December 31, 2009, the Company incurred a net loss of \$6,582,000. Given the nature of the oil and gas business, and the size of Second Wave, the Company must be able to continue to secure sufficient financial resources to achieve its growth objectives. As with the nature of junior oil and gas producers, the Company continues to monitor additional financing opportunities to fund future prospects and commitments. Based on its current forecasts of production volumes, and commodity pricing, the Company currently expects that sufficient liquidity will be available to meet its obligations for the next twelve months.

As at April 29, 2010, the Company has bank lines totaling \$20,000,000 that are currently under review by the Company's senior lender. Although nothing has yet to be finalized, based on discussions with its senior lender to date, management expects that the borrowing base will increase significantly as a result of this review.

During the first quarter of 2010, the Company disposed of its interest in non-core properties for proceeds of \$8,920,000 and closed equity financings for an additional \$20,000,000 to facilitate the acceleration of its capital program at Judy Creek. It is estimated that first quarter 2010 capital expenditures were approximately \$23,500,000.

On October 20, 2009, the Company closed an equity financing for gross proceeds of \$18,002,340. The Company issued 10,715,600 common shares at a price of \$1.40 per share, and 1,765,000 common shares issued on a flow-through basis at a price of \$1.70 per share. The proceeds of the financing were used to fund ongoing exploration and development programs and to repay a term loan of \$3,500,000 to the Company's major shareholder. Under terms of the subscription agreement the Company is required to incur and renounce \$3,000,500 of Canadian Exploration Expenditures to the flow through subscribers on or before December 31, 2010 and February 28, 2010 respectively.

On June 30, 2009, the Company closed a private placement equity financing for aggregate gross proceeds of \$10,644,000. The financing was comprised of 5,165,000 common and 5,710,000 flow-through shares issued at \$0.90 and \$1.05 per share respectively. The Company's major shareholder subscribed for 4,445,000 common shares for gross proceeds of \$4,000,500. Under the terms of the subscription agreement the Company is required to incur and renounce \$5,995,500 of Canadian Exploration Expenditures to the flow through subscribers on or before December 31, 2010 and February 28, 2010 respectively.

On February 17, 2009, the Company closed a private placement equity financing for aggregate gross proceeds of approximately \$3,980,000. A total of 6,015,131 common shares were issued by the Company on a "flow-through" basis. The Company's major shareholder subscribed for 5,757,575 flow-through shares at \$0.66 per share for proceeds of \$3,800,000 while management subscribed for 257,556 flow-through shares at \$0.70 per share for proceeds of \$180,289. As at December 31, 2009, the Company has incurred and renounced the entire amount of its \$180,289 and \$3,800,000 commitment on qualifying Canadian Exploration Expenditures, and qualifying Canadian Development Expenditures respectively.

Subsequent events

On January 11, 2010, the Company disposed of certain non-core oil and gas properties for total consideration of approximately \$8,920,000, comprised of \$5,432,000 cash plus \$3,488,000 of value in common shares of the purchaser. The common shares are considered to be held-for-trading, and were disposed of prior to the end of April 2010, for gross proceeds of approximately \$3,483,000.

On January 22, 2010, the company entered into the following fixed price crude oil and natural gas contracts:

Daily quantity	Term of contract	Price
		Fixed per GJ (AECO Monthly)
Gas (GJs)		
1,200	April 1, 2010 – June 30, 2010	CDN\$5.36
1,200	July 1, 2010 – September 30, 2010	CDN\$5.46

On February 12, 2010, the Company closed a private placement equity financing of 5,000,000 common shares with its majority shareholder for aggregate gross proceeds of \$10,000,000 and through a public offering by prospectus, the Company raised an additional \$10,000,000 through the issuance of 5,000,000 common shares. The proceeds of the financing were used to fund ongoing exploration and development programs.

Quarterly Financial Summary

(\$000's except per boe and per share amounts)	2009				2008				2007			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average production (boe/d)	1,009	990	987	972	1,042	933	783	504	451	244	243	220
Petroleum and natural gas sales	4,522	4,006	3,799	3,325	4,688	7,197	6,326	3,407	2,494	1,120	1,208	1,045
Royalties	(662)	(342)	(346)	(408)	(560)	(905)	(871)	(466)	(338)	(197)	(196)	(165)
Operating expenses	(2,081)	(2,224)	(2,356)	(1,962)	(2,468)	(2,588)	(1,558)	(829)	(1,047)	(246)	(153)	(272)
Transportation expenses	(86)	(98)	(107)	(98)	(163)	(90)	(77)	(54)	(50)	(29)	(27)	(21)
Operating netback	1,693	1,342	990	857	1,497	3,614	3,820	2,058	1,059	648	248	587
Operating netback (per boe) ⁽¹⁾	18.24	14.74	11.02	9.81	15.61	42.10	54.58	44.87	25.51	28.85	34.70	29.72
Cash flow from (used in) operating activities	507	(481)	1,006	348	2,510	2,545	(651)	1,440	(937)	(446)	18	(217)
Per share – basic	0.01	(0.01)	0.03	0.01	0.08	0.05	(0.02)	0.06	(0.07)	(0.05)	-	(0.04)
Per share – diluted	0.01	(0.01)	0.03	0.01	0.08	0.04	(0.02)	0.06	(0.06)	(0.05)	-	(0.03)
Funds from (used in) operations ⁽²⁾	802	399	26	(2)	1,133	2,249	2,596	1,617	(345)	(470)	84	(273)
Per share - basic	0.01	0.01	-	-	0.04	0.07	0.09	0.07	(0.02)	(0.05)	0.01	(0.05)
Per share - diluted	0.01	0.01	-	-	0.02	0.07	0.09	0.07	(0.02)	(0.05)	0.01	(0.04)
Net income (loss)	1,329	(1,645)	(4,138)	(2,128)	(1,587)	665	296	380	(1,640)	(1,102)	(1,200)	395
Per share - basic	0.02	(0.03)	(0.11)	(0.06)	(0.05)	0.02	0.01	0.01	(0.13)	(0.12)	(0.19)	0.07
Per share - diluted	0.02	(0.03)	(0.11)	(0.06)	(0.05)	0.02	0.01	0.01	(0.11)	(0.12)	(0.19)	0.05
Total Assets	89,121	77,348	75,607	79,116	73,649	69,699	66,607	32,242	31,118	22,805	18,866	17,204
Capital expenditures												
Cash	13,373	3,846	1,992	4,903	7,256	8,920	3,953	1,527	12,627	1,034	52	396
Non-cash	214	500	171	(21)	334	3,830	22,801	100	80	-	-	-
Total	13,587	4,346	2,163	4,882	7,590	12,750	26,754	1,627	12,707	1,034	52	396
Long term financial liabilities	3,835	3,807	3,779	7,390	7,365	7,340	7,500	-	8,586	8,525	-	-

(1) Operating netback and operating netback per boe are non-GAAP measures that do not have a standardized meaning as prescribed by GAAP. We consider them to be an important measure as they demonstrate our ability to generate the cash flow necessary to fund future growth through capital investment.

(2) Funds from operations is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. We consider it an important measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.

Contractual Obligations, Commitments, and contingencies

- (a) In connection with the 2009 flow-through equity offerings, the Company is committed to incur \$9,176,289 on qualifying flow through Canadian Exploration Expenditures (“CEE”) and \$3,800,000 on qualifying Canadian Development Expenditures (“CDE”) prior to December 31, 2010. As of December 31, 2009 the Company has a balance of \$6,899,000 remaining to incur related to the CEE flow-through commitments. The Company incurred all of its CDE commitments prior to December 31, 2009.
- (b) In connection with a flow-through equity agreement during 2006, the Company was required under the income tax act to expend amounts renounced to subscribers prior to December 31, 2007. Due to weather related issues, the Company was temporarily delayed and did not complete activities related to \$982,906 in expenditures until February 2008. The Company has advised the Canada Revenue Agency (“CRA”), of the circumstances, paid appropriate interest and penalties and does not intend to re-file the flow-through renunciations to subscribers. In the event that the CRA reassessed the Company’s treatment, the Company could potentially be liable for indemnities to flow through subscribers relating to the delayed expenditures for approximately \$383,333.

- (c) We do not use off-balance sheet arrangements. We are committed to an operating lease for our office space and the future minimum rental payments and estimated operating costs to the end of lease are as follows:

Year	(\$000's)
2010	196
2011	65
Total contractual obligations	261

Related Party Transactions

During the year ended December 31, 2009, the Company entered into the following related party transactions:

- (a) During the year ended December 31, 2009, the Company incurred \$491,900 (2008 – \$822,469) for financing expenses and commitment fees paid to the Company’s major shareholder. As at December 31, 2009 and December 31, 2008, no amounts were payable to the Company’s major shareholder.
- (b) During the year ended December 31, 2009, the Company incurred \$2,809,361 (2008 – \$670,115) for drilling and well services from companies who are under common control and significant influence by Second Wave’s major shareholder. As at December 31, 2009 and December 31, 2008, amounts payable for related party drilling and well servicing was \$1,094,509 and \$87,677 respectively.
- (c) Legal services, disbursements and regulatory costs totaling \$Nil (2008 - \$231,892) payable to a legal firm of which a former director and officer of the Company is counsel. These fees are included in general and administrative expense, share issuance costs and acquisition costs.

The following 2009 financings and debt related activities had related party participants:

- (a) On February 17, 2009, the Company closed a private placement equity financing for aggregate gross proceeds of \$3,980,289. A total of 6,015,131 common shares were issued by the Company on a “flow-through” basis. The Company’s major shareholder subscribed for 5,757,575 flow-through shares at \$0.66 per share for proceeds of \$3,800,000 while management subscribed for 257,556 flow-through shares at \$0.70 per share for proceeds of \$180,289.
- (b) On June 30, 2009, the Company closed a private placement equity financing for aggregate gross proceeds of \$10,644,000. The financing was comprised of 5,165,000 common and 5,710,000 on a “flow-through” basis issued at \$0.90 and \$1.05 per share respectively. The Company’s major shareholder subscribed for 4,445,000 common shares representing gross proceeds of \$4,000,500.
- (c) On October 20, 2009, the Company closed an equity financing for gross proceeds of \$18,002,340. The financing was comprised of 10,715,600 common and 1,765,000 shares on a “flow-through” basis issued at \$1.40 and \$1.70 per share respectively. The Company’s major shareholder subscribed for 2,500,000 common shares representing gross proceeds of \$3,500,000.
- (d) In 2008, the Company had a term loan payable in connection with the acquisition of Milagro Energy Inc., the Company obtained a \$7,500,000 credit facility from its major shareholder. The loan was due on May 8, 2010 and bore interest at the bank’s prime rate plus 2%, and was secured by assets of the Company. This loan was repaid through the conversion into the \$4,000,000 convertible debenture and the issuance of 2,500,000 shares at \$1.40 per share during 2009 as noted in (c) directly above.

All transactions have been completed on the basis of general market terms and conditions and have been recorded at exchange amounts.

Changes in Accounting Policies:

On January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Section 3064, Goodwill and intangible assets, replacing Section 3062, Goodwill and other intangible assets and Section 3450, Research and development costs. This section clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. No changes were required to these financial statements as a result of this change.

In January 2009, the CICA issued EIC-173, “Credit Risk and the Fair Value of Financial Assets and Financial Liabilities” which requires the Company to consider its own credit risk as well as the credit risk of its counterparty when determining the fair value of financial assets and liabilities, including derivative instruments. The accounting treatments provided in EIC-173 have been applied in the preparation of these financial statements and, as required, have been applied retrospectively without restatement of prior periods. The adoption of this standard did not have an impact on the financial statements.

Effective December 31, 2009, the Company adopted amendments to CICA Handbook Section 3862, Financial Instruments - Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. These amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards (“IFRS”).

International Financial Reporting Standards (“IFRS”):

On February 13, 2008, the Canadian Accounting Standards Board confirmed that public entities will be required to adopt International Financial Reporting Standards (“IFRS”) in place of Canadian GAAP for interim and annual reporting purposes effective January 1, 2011.

We will commence reporting financial statements in accordance with IFRS on January 1, 2011, including comparative results, pursuant to the decision made by the CICA. As such, the Company will maintain both Canadian GAAP and IFRS compliant financial statements in 2010.

During 2009 the Company commenced the process of evaluating and planning the implementation of a comprehensive enterprise wide project to manage the transition to IFRS with reporting to both senior management and the Audit Committee. The project has focused on key impact areas including:

- financial reporting,
- systems and processes,
- communication, and
- training

The project is being managed by an in-house team of accounting professionals, who have engaged in IFRS education programs and continue to develop the Company’s adoption to IFRS. The Company’s auditors will be involved throughout the process to ensure the Company’s policies are in accordance with these new standards.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact on the financial statements of adopting IFRS. In addition, due to the anticipated changes to IFRS and International Accounting Standards prior to Second Wave’s adoption of IFRS, management’s plan is subject to change based on new facts and circumstances that arise after the date of this MD&A. It has been determined that accounting for property and equipment will be impacted by the conversion to IFRS, including accounting for and assessing depletion and impairment.

In July 2009, the International Accounting Standards Board (“IASB”) issued an amendment to IFRS 1 “First Time Adoption of International Reporting Standards”. The amendment allows full cost accounting entities to elect, at the time of adoption, to measure exploration and evaluation assets of the amount determined under Canadian GAAP. The amendment will also permit full cost accounting entities to measure, at the time of adoption, oil and gas assets in the development or production phases, by using the total value determined under the entity’s previous GAAP and allocating values at the unit of account level based on the Company’s reserve volumes or reserve values as of the date of conversion. This exemption will relieve the Company from retrospective application of IFRS for its oil and gas assets. The Company currently anticipates that this exemption will be used, however, this will not be determined until the impact analysis and evaluation phase of the conversion project is complete.

It has been determined that accounting for property and equipment will be impacted by the conversion to IFRS, including accounting for and assessing depletion and impairment.

During the project and related transition we will monitor ongoing changes and adjust our transition plans accordingly. Our transition status is currently on track with our implementation schedule.

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During the project and related transition we will monitor ongoing changes and adjust our transition plans accordingly. Our transition status is currently on track with our implementation schedule.

Future Accounting Pronouncements:

Second Wave will be required to adopt the following CICA Handbook sections January 1, 2011.

- (a) The CICA issued Handbook 1582 Business Combinations, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP and IFRS and is effective for business combinations entered into on or after January 1, 2011. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the acquisition date. The adoption of the revised standard is expected to impact Second Wave’s financial statements only to the extent that business combinations are entered into after the effective date.
- (b) Consolidated Financial Statements, Section 1601, which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. It is not anticipated that the adoption of the standard will have an impact on Second Wave’s financial statements.
- (c) Non-controlling interests, Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. This standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. It is not anticipated that the adoption of the standard will have an impact on Second Wave’s financial statements.

Risks and Uncertainties

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company’s other public filings, including its most recently filed Annual Information Form, before making an investment decision in respect of the Company.

Set forth below are certain risk factors that could materially adversely affect our funds from operations, operating results and financial condition.

Competition

The oil and natural gas industry is highly competitive. The Company experiences competition in all aspects of its business, including acquiring reserves, leases, licenses and concessions, obtaining the equipment and labor needed to conduct operations and market natural gas and oil. Competitors include multinational energy companies, other independent natural gas and oil companies and individual producers and operators. Because both crude oil and natural gas are fungible commodities, the principal form of competition with respect to product sales is price competition. Many competitors have financial and other resources substantially greater than those available to us and, accordingly, may be better positioned to acquire and exploit prospects, hire personnel and market production. In addition, many of our competitors may be better able to respond to factors such as changes in worldwide crude oil or natural gas prices, levels of production, the cost and availability of alternative fuels or the application of government regulations. Such factors, which are beyond our control, may affect demand for our crude oil and natural gas production. We expect a high level of competition to continue.

Exploration and development risks

Exploration and development of natural gas and oil involves a high degree of risk that no commercial production will be obtained or that the production will be insufficient to recover drilling and completion costs. The costs of drilling, completing, and operating wells are sometimes uncertain, and cost overruns in exploration and development operations can adversely affect the economics of a project. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including mineral lease title deficiencies, equipment failures, weather conditions, shortages or delays in sourcing qualified personnel, shortages or delays in the delivery of equipment, ability to access surface topography, compliance with government requirements, and fires and explosions. Furthermore, completion of a well does not ensure a profit on the investment or a recovery of the drilling, completion and tie-in costs.

We cannot be certain that the exploratory or development wells we drill will be productive or that we will recover all or any portion of our investments. In order to increase the chances for success, we often invest in seismic or other geoscience data to assist us in identifying potential drilling candidates. Additionally, the cost of drilling, completing and testing wells is often uncertain at the time of our initial investment. Depending on complications encountered while drilling, the final cost of the well may significantly exceed that which we originally estimated.

Commodity price fluctuations

Our products, including crude oil, natural gas, and natural gas liquids and other hydrocarbon products, are commodities. Because our contracts do not fix a long-term price for the products we purchase or sell, market changes in the price of such products can have a direct and immediate effect (whether favorable or adverse) upon our revenues and profitability. Prices for products may be subject to material change in response to relatively minor changes in supply and demand, general economic conditions and other market conditions over which we have no control. Other conditions affecting our business include the level of domestic crude oil and natural gas production, the availability and prices of competing commodities and of alternative energy sources, the availability of local, intraprovincial and interprovincial transportation systems with adequate capacity, the proximity of natural gas production to gas pipelines and facilities, the availability of pipeline capacity, government regulation, the seasons, the weather and the impact of energy conservation efforts.

Estimating reserves and future net cash flows risk

Estimating crude oil, natural gas, and natural gas liquids reserves, and future net cash flows include numerous uncertainties, many of which may be beyond our control. Such estimates are essential in our decision-making, as to whether further investment is warranted. These estimates are derived from several factors and assumptions, some of which are:

- reservoir characteristics based on variable geological, geophysical and engineering assessments;
- future rates of production based on historical production draw-down rates;
- future net cash flows based on commodity price/quality assumptions, production costs, taxes and investment decisions;
- recoverable reserves based on estimated future net cash flows; and
- compliance expectations based on assumed federal, provincial and environmental laws and regulations.

Ultimately, actual production rates, reserves recovered, commodity prices, production costs, government regulations or taxation may differ materially from those assumed in earlier reserve estimates. Higher or lower differences could materially impact our production, revenues, production costs, depletion expense, taxes and capital expenditures.

Reserve estimates and net present values reported by us elsewhere in this document are based on independent third party estimated escalated commodity prices and associated production costs that are assumed for the life of the reserves. Actual future prices and costs may be materially higher or lower.

Replacement of reserves

In general, the rate of production from natural gas and oil properties declines as reserves are depleted. The rate of decline depends on reservoir characteristics and other factors. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, or both, our estimated proved reserves will decline as reserves are produced. Our future crude oil and natural gas production, and therefore cash flow from

operations and net earnings, are highly dependent upon our level of success in finding or acquiring additional economically recoverable reserves. The business of exploring for, developing and acquiring reserves is capital intensive. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves could be materially impaired.

Risks pertaining to acquisitions and joint ventures

As part of implementing our business strategy, we may consider expanding our business through the acquisition of crude oil and natural gas properties or companies. Our ability to expand in this manner would depend upon our ability to identify suitable acquisitions, complete the acquisitions, and effectively integrate any acquired assets or companies into our current business operations. Suitable acquisitions, on terms acceptable to us, may not be available in the future or may require us to assume certain liabilities, including, without limitation, environmental liabilities, known or unknown. Should suitable acquisition candidates be evaluated, we may require debt financing and/or additional equity to be raised to fund the acquisition.

Potential variability in quarterly operating results

The exploration for and development of crude oil and natural gas reserves depends on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up affect access in certain circumstances. Natural gas is used principally as a heating fuel and for power generation. Accordingly, seasonal variations in weather patterns affect the demand for natural gas. Depending on prevailing conditions, the prices received for sales of natural gas are generally higher in winter than summer months, while prices are generally higher in summer than spring and fall months. Accordingly, any increase or decrease in our net operating revenues and their effects on profitability cannot be predicted. Because of the seasonality of our business and continuous fluctuations in the prices of our products, our operating results for any past quarterly period may not necessarily be indicative of results for future periods and there can be no assurance that we will be able to maintain steady levels of profitability on a quarterly or annual basis in the future.

Operating hazards and uninsured risks

The oil and gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally high pressured formations, adverse weather conditions, governmental and political actions, native rights, surface topography, limited or no access during summer months, premature reservoir declines, and environmental hazards such as oil spills, gas leaks and discharges of toxic gases. The occurrence of any of these events with respect to any property operated or owned (in whole or in part) by us could have a material adverse impact on us. We, and the operators of our properties, maintain insurance in accordance with customary industry practices and in amounts that we believe to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

Drilling plans subject to change

A prospect is a property on which our geoscientists have identified what they believe, based on available seismic and geological information, to have indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill a prospect may depend on the following factors: receipt of additional seismic data or reprocessing of existing data and interpretation; material changes in crude oil or natural gas prices; the costs and availability of drilling equipment; success or failure of wells drilled in similar formations, availability of capacity in existing facilities and pipelines; availability and cost of capital; changes in the estimates of costs to drill or complete wells; our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks; decisions of our joint working interest owners; and restrictions imposed by governmental agencies. We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

Shortage of supplies and equipment

Our ability to conduct operations in a timely and cost effective manner is subject to the availability of crude oil and natural gas oil field services, such as rigs, equipment and service crews. Shortage of certain types of equipment and supplies could result in delays in our operations as well as in higher operating and capital costs.

Restoration, safety and environmental risk

Certain laws and regulations exist that require companies engaged in petroleum activities to obtain necessary safety and environmental permits to operate. Such legislation may restrict or delay us from conducting operations in certain geographical areas. Further, such laws and regulations may impose liability on us for remedial and clean-up costs, personal injuries related to safety and environmental damages.

While our safety and environmental activities have been prudent and have enabled us to operate successfully in managing such risks, there can be no assurance that we will always be successful in protecting ourselves from the impact of all such risks. Consistent with our growth in other areas, we seek opportunities for performance improvement in our operating practices.

Government regulation and environmental matters

We are subject to various federal and provincial laws and regulations including environmental laws and regulations. We believe that we are in substantial compliance with such laws and regulations, however, such laws and regulations may change in the future in a manner that will increase the burden and cost of compliance. In addition, we could incur significant liability for damages, cleanup costs and penalties in the event of certain discharges into the environment.

Certain laws and governmental regulations may impose liability on us for personal injuries, clean-up costs, environmental damages and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damage. Accordingly, we may be subject to liability or may be required to cease production from properties in the event of such damages.

Critical Accounting Estimates

Management is required to make judgments in the application of generally accepted accounting principles that may have a significant effect on the financial statements of the Company. The following is a discussion of certain of the accounting estimates used by the Company.

Use of estimates

Inherent in the preparation of financial statements is the use of estimates and assumptions regarding certain assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly actual results may differ from the estimated amounts. Areas that involve the use of significant estimates critical to an understanding of our accounts are outlined below.

While management believes that its estimates have been reasonable in the circumstances, recent events such as the global credit market crisis, the volatility in the price of oil and natural gas, the recession in Canada and the slowdown of economic growth in the rest of the world has created a substantially more volatile business environment. These conditions may limit certain of the Company's previously planned business development activities and it could continue to provide risk for the Company's future. To prepare its financial statements, management has recorded adjustments and included disclosures based on their best estimates of projected business activity and future cash flows.

Full cost accounting

The Company follows the full cost accounting guideline from the CICA to account for its oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of oil and natural gas reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit of production method based on estimated proved reserves, as determined by independent qualified reserve evaluator. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion, depreciation and accretion ("DD&A"). A downward revision in a reserve estimate could result in a higher DD&A rate, and lower earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, the excess must be written off as an expense and charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without the recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or more.

Full cost ceiling test calculations

The full cost method requires us to calculate, whenever there is an indication of impairment, a “ceiling test” or limitation of the amount of properties that can be capitalized on the balance sheet.

The ceiling test is a cost recovery test that compares the expected future net revenues from our oil and gas assets (adjusted for certain items) with the net book value on the balance sheet. If the capitalized costs on the balance sheet are in excess of the calculated ceiling, the excess must be immediately written off as an impairment loss.

The expected future net revenues of proved oil, natural gas, and natural gas liquids reserves is a major component of the ceiling test calculation. This component inherently contains many subjective judgments, such as projected future production rates, product prices, the timing of future expenditures, and the economic productive limit of our assets. We utilize the resources of an independent reserves evaluator to evaluate all of our reserves on an annual basis.

The passage of time provides additional qualitative information regarding our reserves that could result in reserve revisions. Significant decreases in proven reserves or product pricing could result in a full cost ceiling test write-down.

Significant changes in proven reserves will also impact the calculation of depletion.

Asset retirement obligations

The Company records a liability for the fair value of legal obligation associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related assets and the asset retirement obligation. The total amount of the asset retirement obligation is an estimate based on the company’s net ownership interest in all wells and facilities and the estimated costs to abandon and reclaim the wells and facilities and the estimated timing. The Company uses the remaining economic reserve life of a property, as independently evaluated by reserve engineers, to assist with the timing of abandonments. Significant changes in any of the assumptions could alter the amount of asset retirement obligations and related accretion and depletion.

The asset retirement obligation liabilities are carried on the balance sheet at their discounted present value and are accreted over time for the change in their present value.

Reserves determination

Proved crude oil and natural gas, and natural gas liquids reserves (“NGL’s”) are used in determining depletion rates. The magnitude of the borrowing base available to us from our lender and the ceiling test are based on management’s best estimates, and are subject to uncertainty. Independent reserve engineers are used by the Company to assist in the reserve evaluation process. Geological, geophysical and engineering data, the reservoirs and deposits of crude oil, natural gas, and NGL’s are examined to determine quantities available for future production, given existing operating and economic conditions and technology. The process of evaluating recoverable reserves is an ongoing process impacted by current production, continuing development activities and changing economic conditions as reflected in crude oil and natural gas pricing and costs. As a result, reserves are estimates which are subject to variability.

Stock-based compensation

In accordance with CICA Handbook Section 3870, “Stock-based Compensation and Other Stock-based Payments”, we follow the fair value method for valuing stock option grants. Under this method, compensation cost attributable to stock options is measured at fair value, using the Black-Scholes option pricing model, at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid and the associated cost recorded in contributed surplus is recorded as an increase to total capital.

Financial derivatives

The Company may use financial instruments from time to time to hedge its exposures to commodity prices. The mark-to-market valuations of these contracts are presented in the Company's financial statements. These valuations are based on forward looking estimates including but not limited to volatility, interest rates, and commodity prices.

Revenue recognition

Revenue is recorded in the period when the proceeds become receivable and measurable and collection is reasonably assured. Under certain agreements, we receive oil and natural gas revenues net of operating and capital costs incurred by the working interest participants. The time that the net revenues become receivable and collection is reasonably assured depends on the terms and conditions of the relevant agreements and the practices followed by the operator.

Income taxes

The determination of the company's income and other tax liabilities required interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability and expense may differ from that estimated and recorded.

Additional information

Additional information relating to Second Wave, including its most recently filed Annual Information Form, may be found on our website at www.secondwavepetroleum.com or on SEDAR at www.sedar.com.