FINANCIAL AND OPERATING SUMMARY

($000s except per share amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2011	2010	% change	**2011**	2010	% change
Financials highlights						
Oil and NGL sales	**36,954**	15,014	146%	**111,705**	47,685	134%
Natural gas sales	**5,741**	3,322	73%	**19,548**	10,029	95%
Other revenue	**117**	208	(43%)	**239**	213	12%
Total oil, natural gas, and NGL revenue	**42,812**	18,544	131%	**131,492**	57,927	127%
Funds from Operations[1]	**22,088**	977	2,161%	**57,789**	18,764	208%
Per share basic ($)	**0.36**	0.02	1,700%	**1.00**	0.51	96%
Per share diluted ($)	**0.35**	0.02	1,650%	**0.98**	0.51	92%
Net income (loss)	**(5,531)**	(3,999)	nm	**2,095**	(7,695)	nm
Per share basic ($)	**(0.09)**	(0.08)	nm	**0.04**	(0.21)	nm
Per share diluted ($)	**(0.09)**	(0.08)	nm	**0.04**	(0.21)	nm
Total cash-based capital expenditures[2]	**46,741**	66,239	(29%)	**165,158**	117,339	41%
Net debt at end of period[3]	**97,204**	46,240	110%	**97,204**	46,240	110%
Operating highlights						
Production:						
Oil and NGL (bbls per day)	**4,534**	2,308	96%	**3,604**	1,871	93%
Natural gas (mcf per day)	**17,885**	10,182	76%	**14,133**	6,930	104%
Total (boe per day) (6:1)	**7,514**	4,005	88%	**5,960**	3,026	97%
Average realized price (excluding hedges):						
Oil and NGL ($per bbl)	**88.60**	70.70	25%	**84.91**	69.83	22%
Natural gas ($ per mcf)	**3.49**	3.55	(2%)	**3.79**	3.96	(4%)
Realized gain(loss) on financial contracts ($ per boe)	**(1.62)**	1.92	nm	**(1.62)**	2.53	nm
Net back (excluding hedges) ($ per boe)						
Oil, natural gas and NGL sales	**61.93**	50.33	23%	**60.45**	52.45	15%
Royalties	**(7.05)**	(6.43)	10%	**(8.06)**	(7.35)	10%
Operating expenses	**(14.92)**	(14.87)	0%	**(15.58)**	(15.25)	2%
Transportation expenses	**(1.41)**	(1.72)	(18%)	**(2.23)**	(2.20)	1%
Operating netback	**38.55**	27.31	41%	**34.58**	27.65	25%
G&A expenses	**(3.00)**	(7.02)	(57%)	**(4.37)**	(6.06)	(28%)
Interest expense	**(1.22)**	(0.80)	53%	**(1.46)**	(0.90)	62%
Corporate netback	**34.33**	19.49	76%	**28.75**	20.69	39%
Common shares (000s)						
Common shares outstanding, end of period	**63,040**	56,095	12%	**63,040**	56,095	12%
Weighted average basic shares outstanding	**62,125**	53,065	17%	**57,622**	36,468	58%
Stock option dilution (treasury method)	**1,190**	-	nm	**1,136**	-	nm
Weighted average diluted shares outstanding	**63,314**	53,065	19%	**58,758**	36,468	61%

1 Management uses funds from operations (before changes in non-cash working capital and non-recurring recapitalization costs) to analyze operating performance and leverage. Funds from operations as presented does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures for other entities.

2 Please see capital expenditures note.

3 The Corporation defines net debt as outstanding bank debt plus or minus working capital excluding the fair value of financial contracts.

OVERVIEW, HIGHLIGHTS AND FORECAST

Surge is pleased with the drill bit driven growth it achieved in 2011. The Corporation is well positioned with three core areas each with considerable primary light oil resource and secondary recovery potential. Surge continues to capture more light oil resource as shown with its accretive acquisition of 1,200 barrels per day of light oil in January of 2012. Surge sees the potential to grow this acquisition to more than 4,000 barrels of light oil per day with the successful implementation of waterflood.

Surge drilled at each of its light oil resource plays during 2011 with continued excellent results. The Corporation drilled a total of 38 gross (35.36 net) wells, achieving a 100 percent success rate and averaged more than 7,500 boe per day in the fourth quarter. Primarily as a result of this successful drilling, Surge more than tripled funds from operations, almost doubled production and achieved leading capital efficiencies in 2011.

ACHIEVEMENTS AND HIGHLIGHTS

- **Achieved a 100 percent success rate** drilling 15 gross (13.11 net) wells in the fourth quarter of 2011. During 2011, Surge achieved a 100 percent success rate drilling 38 gross (35.36 net) wells.
- **Funds from operations more than tripled** to $57.8 million during 2011 from $18.8 million during 2010. Increased funds from operations per share by 96 percent to $1.00 during 2011 from $0.51 during 2010.
- **Increased production by 97 percent** to 5,960 boe per day during 2011 from an average of 3,026 boe per day during 2010.
- **Increased Surge's operating netback by 41 percent** to $38.55 for the fourth quarter of 2011 as compared to $27.31 in the fourth quarter of 2010.
- **More than 87 percent of Surge's revenue resulted from oil and natural gas liquids production**, with less than 13 percent derived from natural gas production.
- **Increased production by 88 percent** to 7,514 boe per day in the fourth quarter of 2011 from an average of 4,005 boe per day in the fourth quarter of 2010.
- **Increased production by 22 percent** to 7,514 boe per day in the fourth quarter of 2011 from an average of 6,166 boe per day in the third quarter of 2010. The combination of drilling in early 2012 and the closing of the light oil acquisition in January 2012 drives Surge to forecast its **oil and natural gas liquids production weighting to increase to over 70 per cent** .
- **Surge achieved its upwardly revised 2011 exit production rate** of 7,800 boe per day, **a 73 percent increase** over the 2010 exit of approximately 4,500 boe per day.
- In the fourth quarter of 2011, **approximately 87 percent of Surge's revenue resulted from oil and natural gas liquids production.**
- Achieved Proved plus Probable finding and development costs **(F&D) of $14.02 per boe**, including the change in Future Development Capital (FDC).
- **Achieved a recycle ratio of 2.7** with F&D costs of $14.02 per boe, including the change in FDC and based on Surge's fourth quarter 2011 netback of $38.55 per boe.
- Achieved Proved plus Probable finding, development and acquisition costs **(FD&A) of $16.65 per boe**, including the change in FDC, resulting in a recycle ratio of 2.3 based on Surge's fourth quarter 2011 netback of $38.55 per boe.
- **Increased Proved plus Probable reserves by 52 percent** to 32.2 million boe over December 31, 2010 reserves of 21.2 million boe.
- **Increased Proved plus Probable Reserves per share by 32 percent** (fully diluted).
- Achieved a **Proved plus Probable reserves replacement ratio of 6.1** based on the Company's 2011 average production for the year of 5,960 boe per day.
- Achieved a **Proved plus Probable Reserve Life Index (RLI) of 11.7 years** based on the Company's 2011 fourth quarter average production rate of 7,514 boe per day.
- In the fourth quarter of 2011, Surge issued 6,897,000 shares at a price of $8.70 per share for gross proceeds of $60 million. The increase in bank line during the third quarter to $150 million, combined with the equity issue, gives Surge considerable financial flexibility as it begins to execute on its 2012 capital program.

- **Surge obtained a Toronto Stock Exchange (TSX) listing** and began trading on the TSX under the symbol SGY on October 21, 2011.
- During the fourth quarter of 2011, **Surge announced the accretive acquisition of a private company with 1,200 barrels per day of light oil production**. The acquisition and the anticipated increase in its bank line from $150 million to $175 million closed in January of 2012.
- **Increased Surge's operating netback by 41 percent** to $38.55 for the fourth quarter of 2011 as compared to $27.31 in the fourth quarter of 2010.
- **Increased Surge's operating netback by 25 percent** to $34.58 during 2011 as compared to $27.65 during 2010.
- **Increased Surge's operating netback by 17 percent** to $38.55 for the fourth quarter of 2011 as compared to $32.86 in the third quarter of 2011. The management team continues to focus on finding efficiencies within existing operations and expects operating netbacks to continue to grow.

Netback Comparison

	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010
Average production (boe per day)	**7,514**	6,166	5,051	5,076	4,005
Revenue	**$ 61.93**	$ 58.19	$ 64.83	$ 56.64	$ 50.33
Royalties	**(7.05)**	(8.38)	(9.24)	(8.02)	(6.43)
Operating costs	**(14.92)**	(14.79)	(16.39)	(16.73)	(14.87)
Transportation costs	**(1.41)**	(2.16)	(3.25)	(2.54)	(1.72)
Operating netback	**$ 38.55**	$ 32.86	$ 35.95	$ 29.35	$ 27.31

OUTLOOK & FORECAST

In less than two years, Surge has positioned itself in three core areas, assembled more than 490 gross oil drilling locations and gained exposure to an internally estimated DPIIP ("Discovered Petroleum Initially In Place")[1] of more than 440 (gross) million barrels of oil.

Surge continues to add light oil resource to its portfolio as shown with the accretive acquisition of a private company in January 2012. Through the acquisition, Surge acquired 1,200 bbls per day of high quality, high netback, focused Slave Point/Gilwood light oil assets in the early stages of primary development in the Nipisi/Gift area of Western Alberta. Surge estimates there to be 65 million barrels of DPIIP in the Slave Point pool with less than one percent of the oil recovered to date. Surge believes there is potential to grow production to 2,500 bbls per day of oil over the next two years under primary development and to more than 4,000 barrels per day of oil over the next few years with the implementation of a successful waterflood program.

When combined on a pro forma basis with the light oil acquisition closed in early January, Surge has more than 23 million barrels of proved plus probable oil and NGL reserves with the potential to recover more than 56 million additional barrels of light oil through its drilling inventory and the successful implementation of waterflood.

In 2012, Surge will continue to grow organically by drilling in each of its core areas and will continue to make accretive acquisitions that fit its business plan. Surge is committed to delivering top quartile corporate performance and creating value for shareholders by growing reserves, cash flow and production on a per share basis.

As a result of our very successful development drilling results and strategic acquisitions, Surge is well positioned to meet or exceed its 2012 exit production rate of 11,000 barrels per day with oil and NGLs growing to 77 percent of total production.

[1] Discovered Petroleum Initially In Place (DPIIP) is defined as quantity of hydrocarbons that are estimated to be in place within a known accumulation, plus those estimated quantities in accumulations yet to be discovered. There is no certainty that it will be commercially viable to produce any portion of the resources. There is no certainty that it will be commercially viable to produce any portion of the resources. A recovery project cannot be defined for this volume of DPIIP at this time, and as such it cannot be further sub-categorized.

Annualized 2012 exit funds from operations are forecast at $166 million[2] ($2.34 per share) and a debt to cash flow ratio of less than one times.

Surge is an oil focused oil and gas company with operations throughout Alberta, Manitoba and North Dakota. Surge's common shares trade on the Toronto Stock Exchange under the symbol SGY. At year end, the Corporation had 63.0 million basic and 70.1 million fully diluted common shares outstanding. After the close of the acquisition in January of 2012, the Corporation had 70.1 million basic and 78.0 million fully diluted common shares outstanding.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) of the consolidated financial position and results of operations of Surge Energy Inc. ("Surge" or the "Corporation"), which includes its subsidiaries and partnership arrangements, is for the three months and years ended December 31, 2011 and 2010. For a full understanding of the financial position and results of operations of the Corporation, the MD&A should be read in conjunction with the documents filed on SEDAR, including historical financial statements, MD&A and the Annual Information Form (AIF). These documents are available at www.sedar.com.

Surge's MD&A, together with the year-end financial statements now comply with International Financial Reporting Standards ("IFRS") as of January 1, 2011. Surge has provided IFRS accounting policies and prepared reconciliations between previous Canadian generally accepted accounting principles ("GAAP") and IFRS in the notes to its year-end financial statements. Comparative numbers for 2010 have also been updated to reflect IFRS changes. These changes have not had an impact on the operating assets of Surge but have significantly modified Surge's financial statements and related notes.

Further information on the impact of the changeover to IFRS is provided in the "Accounting Policies" section of the MD&A.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements.

More particularly, this MD&A contains statements concerning anticipated: (1) capital expenditures for 2012, (2) exploration, development, and acquisition activities, (3) average and exit oil, NGLs and natural gas production during 2012, (4) production weighting for 2012 (5) construction of new facilities, (6) funds from operations, (7) debt and bank facilities, (8) operating and transportation costs and (9) the availability and successful completion of acquisitions. The forward-looking statements are based on certain key expectations and assumptions made by Surge, including expectations and assumptions concerning the performance of existing wells and success obtained in drilling new wells, anticipated expenses, cash flow and capital expenditures, the application of regulatory and royalty regimes and prevailing commodity prices and economic conditions.

Although Surge believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Surge can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Certain of these risks are set out in more detail in Surge's Annual Information Form which has been filed on SEDAR and can be accessed at www.sedar.com.

The forward-looking statements contained in this MD&A are made as of the date hereof and Surge undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

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[2] Based on US$105.00/bbl WTI, $2.95/GJ AECO, US$/CDN$ exchange rate of $1.00.

All amounts are expressed in Canadian dollars unless otherwise noted. Oil, natural gas and natural gas liquids reserves and volumes are converted to a common unit of measure, referred to as a barrel of oil equivalent (boe), on the basis of 6,000 cubic feet of natural gas being equal to one barrel of oil. This conversion ratio is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. It should be noted that the use of boe might be misleading, particularly if used in isolation.

The terms "funds from operations", "funds from operations per share", and "netback" used in this discussion are not recognized measures under International Financial Reporting Standards (IFRS). Management believes that in addition to net income, funds from operations and netback are useful supplemental measures as they provide an indication of the results generated by the Corporation's principal business activities before the consideration of how those activities are financed or how the results are taxed. Investors are cautioned, however, that these measures should not be construed as alternatives to net income determined in accordance with IFRS, as an indication of Surge's performance.

Surge's method of calculating funds from operations may differ from that of other companies, and, accordingly, may not be comparable to measures used by other companies. Surge determines funds from operations as cash flow from operating activities before changes in non-cash working capital and non-recurring recapitalization costs as follows:

Funds from Operation

($000s)	**Q4 2011**	Q3 2011	Q2 2011	Q1 2011	Q4 2010
Cash flow from operating activities (per IFRS)	**$ 19,073**	$ 17,272	$ 11,338	$ 9,007	$ 473
Change in non-cash working capital	**3,015**	(3,270)	560	765	6,801
Transaction costs from investing to operating	**-**	-	-	-	(888)
Non-recurring recapitalization costs	**-**	-	-	-	(5,409)
Funds from operations	**$ 22,088**	$ 14,002	$ 11,898	$ 9,772	$ 977

Funds from operations per share is calculated using the weighted average basic and diluted shares used in calculating income per share. Operating and corporate netbacks are also presented. Operating netbacks represent Surge's revenue, excluding realized and unrealized gains or losses on financial contracts, less royalties and operating and transportation expenses. Corporate netbacks represent Surge's operating netback, less general and administrative and interest expenses, in order to determine the amount of funds generated by production. Operating and corporate netbacks have been presented on a per barrels of oil equivalent ("boe") basis.

Surge's management is responsible for the integrity of the information contained in this report and for the consistency between the MD&A and financial statements. In the preparation of these statements, estimates are necessary to make a determination of future values for certain assets and liabilities. Management believes these estimates have been based on careful judgments and have been properly presented. The financial statements have been prepared using policies and procedures established by management and fairly reflect Surge's financial position, results of operations and funds from operations.

Surge's Board of Directors and Audit Committee have reviewed and approved the financial statements and MD&A. This MD&A is dated March 21, 2012.

OPERATIONS

	Drilling		Success rate	Working
	Gross	Net	(%) gross	interest (%)
Q1 2011	4	4	100%	100%
Q2 2011	1	0.54	100%	54%
Q3 2011	18	17.71	100%	98%
Q4 2011	15	13.11	100%	87%
Total	**38**	**35.36**	**100%**	**93%**

Surge achieved a 100 percent success rate during the year ended December 31, 2011, drilling 38 gross (35.36 net) wells. The 38 gross wells drilled year to date include eight wells at Valhalla South, five wells at Windfall, two wells at Sounding Lake, six wells in the Silver area, two wells in the North Dakota area, one well in the Goose River area and 14 wells at Waskada. Only eight of the 15 wells drilled in the fourth quarter were producing at quarter end with the rest to be completed and brought on production during the first quarter of 2012.

Production

	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010
Oil and NGL (bbls per day)	**4,534**	3,781	2,995	3,090	2,308
Natural gas (mcf per day)	**17,885**	14,313	12,334	11,915	10,182
Total (boe per day) (6:1)	**7,514**	6,166	5,051	5,076	4,005
% Oil and NGL	**60%**	61%	59%	61%	58%

Surge achieved an average production rate of 7,514 boe per day in the fourth quarter of 2011, an 88 percent increase from the fourth quarter of 2010 average production rate of 4,005 boe per day. Surge achieved an average production rate of 5,960 boe per day in 2011, a 97 percent increase as compared to the average 2010 production rate of 3,026 boe per day. The increase in the production volumes for both the fourth quarter and full year of 2011 compared to the same period in 2010 was primarily due to the results of the 2011 drilling program.

Surge realized a 60 percent oil and natural gas liquids production weighting in the fourth quarter of 2011. Surge realized average oil and natural gas liquids production of 4,534 bbls per day for the fourth quarter of 2011.

With the combination of drilling in early 2012 and the closing of the private company light oil acquisition on January 6, 2012, Surge forecasts it’s oil and natural gas liquids production weighting to increase to over 70 percent.

Oil, Natural Gas and NGL, Financial Contracts and Other Revenues

A 23 percent increase in revenue per boe, combined with an 88 percent increase in production, resulted in revenues of $42.8 million in the fourth quarter of 2011, up 131 percent from $18.5 million in the same period of 2010. During 2011, a 15 percent increase in revenue per boe, combined with a 97 percent increase in production, resulted in revenues of $131.5 million, up 127 percent from $57.9 million during the same period in 2010.

Surge had certain financial contracts in place as of December 31, 2011. Surge recognized an unrealized loss of $6.5 million and a realized loss of $1.1 million on its financial contracts in the fourth quarter of 2011. This compares to an unrealized loss of $2.6 million and a realized gain of $0.7 million on its financial contracts in the fourth quarter of 2010. In 2011, Surge recognized an unrealized loss of $2.3 million and a realized loss of $3.5 million on its financial contracts.

The realized financial contract loss resulted in a decrease of $1.62 per boe to average revenue, including financial contracts, during both the fourth quarter and full year 2011. The unrealized financial contract loss resulted in a decrease of $1.07 per boe to average revenue, including financial contracts, during 2011.

Please refer to the "Financial Instruments" section of this MD&A for further details on these oil and natural gas commodity contracts, and interest rate swaps.

Prices

The Corporation realized average revenue of $61.93 per boe in the fourth quarter of 2011, before realized financial contract losses, an increase of 23 percent from the $50.33 per boe recorded in the same period of 2010. During 2011, Surge realized average revenue of $60.45 per boe, before realized financial contract losses, an increase of 15 percent from the $52.45 per boe during the same period of 2010.

The Corporation realized an average of $88.60 per bbl of oil and natural gas liquids in the fourth quarter of 2011, an increase of 25 percent from the $70.70 per bbl realized in the same period of 2010. This compares to an average Edmonton Light Sweet price of $97.35 per bbl during the fourth quarter of 2011, which increased 21 percent per barrel from the $80.33 per bbl during the same period of 2010. The increase in oil and natural gas liquids prices is relatively consistent with the increase in benchmark prices, after adjusting for oil and NGL price differentials.

The Corporation realized an average of $84.91 per bbl of oil and natural gas liquids during 2011, an increase of 22 percent from the $69.83 per bbl realized during the same period of 2010. This compares to an average Edmonton Light Sweet price of $94.83 per bbl during 2011, which increased 22 percent per barrel from the $77.48 per bbl during the same period of 2010. The increase in oil and natural gas liquids prices is consistent with the increase in benchmark prices.

The Corporation realized an average natural gas price of $3.49 per mcf in the fourth quarter of 2011, a two percent decrease from the $3.55 per mcf averaged in the same period of 2010. This compares to an average Alberta Plant Gate reference price of $3.01 per mcf in the fourth quarter of 2011, which decreased by 12 percent from the $3.43 per mcf in the same period of 2010. The lower decrease in realized natural gas prices as compared to average Alberta Plant Gate reference pricing is due to higher than average heat content associated with the natural gas produced in the Valhalla and Windfall areas.

The Corporation realized an average natural gas price of $3.79 per mcf during 2011, a four percent decrease from the $3.96 per mcf averaged during the same period of 2010. This compares to an average Alberta Plant Gate reference price of $3.43 per mcf during 2011, which decreased nine percent from the $3.79 per mcf in the same period of 2010. The decrease in natural gas prices is less than the decrease in benchmark prices, due to the higher than average heat content associated with the natural gas produced in the Valhalla and Windfall areas.

In the fourth quarter of 2011, approximately 86 percent of Surge's revenue resulted from oil and natural gas liquids production, with approximately 14 percent derived from natural gas.

Realized financial contract losses resulted in a decrease of $1.62 per boe to the average revenue including financial contracts in the fourth quarter of 2011.

Realized financial contract losses resulted in a decrease of $1.62 per boe to the average revenue including financial contracts during 2011.

Revenue and Realized Prices

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per amount)	**2011**	2010	% Change	**2011**	2010	% Change
Oil and NGL	**36,954**	15,014	146%	**111,705**	47,685	134%
Natural gas	**5,741**	3,322	73%	**19,548**	10,029	95%
Processing and other	**117**	208	(43%)	**239**	213	12%
Total oil, natural gas and NGL revenue	**42,812**	18,544	131%	**131,492**	57,927	127%
Oil and NGL ($ per bbl)	**88.60**	70.70	25%	**84.91**	69.83	22%
Natural gas ($ per mcf)	**3.49**	3.55	(2%)	**3.79**	3.96	(4%)
Total oil, natural gas and NGL revenue ($ per boe)	**61.93**	50.33	23%	**60.45**	52.45	15%
Unrealized loss on commodity contracts ($ per boe)	**(9.45)**	(7.19)	31%	**(1.07)**	(2.13)	(50%)
Realized gain (loss) on commodity contracts ($ per boe)	**(1.62)**	1.92	nm	**(1.62)**	2.53	nm
Total oil, natural gas, and NGL revenue after commodity contracts ($ per boe)	**50.86**	45.06	13%	**57.76**	52.85	9%
Reference Prices						
Edmonton Light Sweet ($ per bbl)	**97.35**	80.33	21%	**94.83**	77.48	22%
Alberta Plant Gate ($ per mcf)	**3.18**	3.43	(7%)	**3.43**	3.79	(9%)

Benchmark prices

	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010
($ per bbl)					
Benchmark - Edmonton Light Sweet	**97.35**	91.74	103.07	87.77	80.33
Surge realized prices	**88.60**	80.29	92.36	77.86	70.70
Difference	**(8.75)**	(11.45)	(10.71)	(9.91)	(9.63)
% Difference	**(9%)**	(12%)	(10%)	(11%)	(12%)
($ per mcf)					
Benchmark - Alberta Plant Gate	**3.18**	3.53	3.80	3.56	3.43
Surge realized prices	**3.49**	3.81	4.13	3.88	3.55
Difference	**0.31**	0.28	0.33	0.32	0.12
% Difference	**10%**	8%	9%	9%	3%

ROYALTIES

Surge realized royalty expense of $4.9 million in the fourth quarter of 2011, compared to $2.4 million in the same period of 2010. The increase in royalties during the fourth quarter is primarily the result of increased oil production. During 2011, Surge realized royalty expense of $17.5 million compared to $8.1 million in the same period of 2010. The reduction in royalties as a percentage of revenue during both the three months and year ended December 31, 2011 is primarily the result of the Alberta government's royalty incentive program, which reduced royalties on newly drilled horizontal wells. On January 1, 2009 the Alberta government's Alberta Royalty Framework (ARF) took effect.

During the three months ended December 31, 2011, Surge recorded $1.9 million of drilling royalty credit adjustments as a decrease to capital costs. The drilling royalty credit portion of the 2009 incentive program concluded on March 31, 2011. Credits recorded during 2011 are the result of adjustments relating to both 2010 and the first quarter of 2011.

As royalties under the ARF are sensitive to both commodity prices and production levels, the estimated ARF and corporate royalty rates will fluctuate with commodity prices, well production rates, production decline of existing wells, and performance and location of new wells drilled.

Royalties

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Royalties	**4,875**	2,371	106%	**17,537**	8,122	116%
% of Revenue	**11%**	13%	(2%)	**13%**	14.0%	(7%)
$ per boe	**7.05**	6.43	10%	**8.06**	7.35	10%

OPERATING EXPENSES

Operating expenses per boe in the fourth quarter of 2011 were relatively flat at $14.92 per boe as compared to $14.87 per boe in the same period of 2010. Operating expenses per boe during 2011 were $15.58 per boe, up two percent from $15.25 per boe during the same period of 2010.

Operating expenses per boe during 2011 were impacted by wet conditions in Waskada and Windfall. Start-up costs in the first quarter of 2011 and the impact of the shut-in production in the second quarter of 2011 negatively impacted per boe expenses in the Waskada area. Additionally, 2011 operating expenses for the full year were impacted by higher operating expenses in areas acquired in the third quarter of 2010.

The management team continues to focus on finding efficiencies within existing operations and expects operating expenses per boe to decline throughout 2012. The management team is forecasting to reduce combined operating and transportation costs to less than $13.50 per boe during 2012.

Operating Expenses

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Operating expenses	**10,319**	5,481	88%	**33,885**	16,841	101%
$ per boe	**14.92**	14.87	0%	**15.58**	15.25	2%

TRANSPORTATION EXPENSES

Transportation expenses per boe decreased 35 percent in the fourth quarter to $1.41 per boe as compared to $2.16 per boe in the third quarter of 2011. This decrease is primarily due to additional volumes in the pipeline connected areas of Valhalla and Silver.

Transportation expenses per boe decreased 18 percent in the fourth quarter of 2011 to $1.41 per boe as compared to $1.72 recorded in the same period of 2010. Transportation expenses per boe during 2011 were $2.23 per boe, up one percent from $2.20 per boe during the same period of 2010.

The increase in transportation expenses per boe during 2011 as compared to the same periods of 2010 was primarily the result of increased trucking costs due to wet conditions in the second and third quarter at Windfall and delivery adjustments in Valhalla.

The management team continues to focus on finding efficiencies within existing operations and expects operating expenses per boe to decline throughout 2012. The management team is forecasting to reduce combined operating and transportation costs to less than $13.50 per boe during 2012.

Transportation Expenses

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Transportation expenses	**976**	634	54%	**4,860**	2,426	100%
$ per boe	**1.41**	1.72	(18%)	**2.23**	2.20	1%

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

Net G&A expenses per boe for the fourth quarter of 2011 decreased 57 percent to $3.00 per boe as compared to $7.02 per boe in the same period of 2010. Net G&A expenses per boe decreased 39 percent in the fourth quarter to $3.00 per boe as compared to $4.92 per boe in the third quarter of 2011. G&A expenses for the fourth quarter of 2011, net of recoveries and capitalized amounts of $2.1 million, were $2.1 million, compared to $2.6 million in the same period of 2010, after recoveries and capitalized amounts of $1.7 million. The decrease in G&A per boe is primarily due to the increased production levels in the fourth quarter of 2011, as compared to the same period in 2010.

Net G&A expenses per boe during 2011 decreased 28 percent to $4.37 per boe as compared to $6.06 per boe in 2010. G&A expenses during 2011, net of recoveries and capitalized amounts of $7.2 million, were $9.5 million, compared to $6.7 million in the same period of 2010, after recoveries and capitalized amounts of $3.1 million. The decrease in G&A per boe is primarily due to the increased production levels during 2011, as compared to 2010.

The management team continues to focus on general and administrative expenditure efficiencies.

G&A Expenses

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
G&A expenses	**4,127**	4,269	(3%)	**16,762**	9,787	71%
Recoveries and capitalized amounts	**(2,051)**	(1,682)	22%	**(7,247)**	(3,096)	134%
Net G&A expenses	**2,076**	2,587	(20%)	**9,515**	6,691	42%
Net G&A expenses $ per boe	**3.00**	7.02	(57%)	**4.37**	6.06	(28%)

TRANSACTION COSTS

Transaction costs of $0.2 million or $0.11 per boe during 2011 were related to evaluation and review of business and property acquisitions. This is compared to $1.0 million or $0.33 per boe during the same period of 2010. The 76 percent decrease in transaction cost in the current year compared to 2010 is due to fewer acquisitions in 2011.

Transaction Costs

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Transaction costs	**151**	121	25%	**246**	1,009	(76%)
$ per boe	**0.22**	0.91	(76%)	**0.11**	0.33	(67%)

FINANCE EXPENSES

Surge incurred interest expense of $0.8 million or $1.22 per boe in the fourth quarter of 2011 as compared to $0.3 million or $0.80 per boe in the same period of 2010. The increase per boe during the fourth quarter of 2011 is due to higher debt levels as compared to the same period of 2010. During 2011, Surge incurred an interest expense of $3.2 million or $1.46 per boe, compared to $1.0 million or $0.90 per boe during 2010.

Accretion represents the change in the time value of the decommissioning liability. Accretion expense per boe decreased for the three months and year ended December 31, 2011 compared to the same period of 2010 due to new obligations from wells drilled, the acquisition of assets, and higher production levels. The underlying liability may increase over a period of time, based on new obligations incurred from drilling wells, constructing facilities, acquiring operations or adjusting future estimates of timing or amounts. Similarly, this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations.

Finance Expenses

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Interest expense	**843**	295	186%	**3,176**	998	218%
$ per boe	**1.22**	0.80	53%	**1.46**	0.90	62%
Accretion expense	**241**	191	26%	**1,017**	719	41%
$ per boe	**0.35**	0.52	(33%)	**0.47**	0.65	(28%)
Finance expenses	**1,084**	486	123%	**4,193**	1,717	144%
$ per boe	**1.57**	1.32	19%	**1.93**	1.55	25%

NETBACKS

During the quarter, Surge's operating netback (defined as revenue excluding realized and unrealized gains or losses on financial contracts per boe less royalties, operating and transportation expenses on a per boe) was $38.55, a 41 percent increase over the $27.31 recorded during the same period of 2010. The increase in operating netback was attributable to a 23 percent increase in revenue per boe, offset by a 10 percent increase in royalties and an 18 percent decrease in transportation expense per boe, as compared to the same period of 2010. The increase in corporate netback was impacted by a 57 percent decrease in G&A expense per boe in 2011 and offset by a 53 percent increase in interest expense per boe, as compared to the same period of 2010.

During 2011, the operating netback per boe (defined as revenue excluding realized and unrealized gains or losses on financial contracts per boe less royalties, operating and transportation expenses on a per boe basis) of the Corporation was $34.58, a 25 percent increase over the $27.65 recorded during the same period of 2010. The increase in operating netback was largely due to a 15 percent increase in revenue per boe, offset by a 10 percent increase in royalties per boe, a two percent increase in operating expense per boe, and a one percent increase in transportation expense per boe, as compared to the same period of 2010. The increase in corporate netback was impacted by a 28 percent decrease in G&A expense per boe in 2011 and offset by a 62 percent increase in interest expense per boe, as compared to the same period of 2010.

The management team continues to focus on finding efficiencies within existing operations and expects its per boe costs to continue to improve.

Corporate Average Netbacks

	Three Months Ended December 31,			Years Ended December 31,		
($ per boe, except production)	**2011**	2010	% Change	**2011**	2010	% Change
Average production (boe per day)	**7,514**	4,005	88%	**5,960**	3,026	97%
Revenue	**61.93**	50.33	23%	**60.45**	52.45	15%
Royalties	**(7.05)**	(6.43)	10%	**(8.06)**	(7.35)	10%
Operating costs	**(14.92)**	(14.87)	-%	**(15.58)**	(15.25)	2%
Transportation costs	**(1.41)**	(1.72)	(18%)	**(2.23)**	(2.20)	1%
Operating netback	**38.55**	27.31	41%	**34.58**	27.65	25%
G&A expense	**(3.00)**	(7.02)	(57%)	**(4.37)**	(6.06)	(28%)
Interest expense	**(1.22)**	(0.80)	53%	**(1.46)**	(0.90)	62%
Corporate netback	**34.33**	19.49	76%	**28.75**	20.69	39%

FUNDS FROM OPERATIONS AND CASH FLOW FROM OPERATIONS

During the three months ended December 31, 2011, funds from operations increased to $22.1 million compared to $1.0 million in the same period of 2010. On a per share basis, funds from operations increased to $0.36 per basic share in the fourth quarter of 2011 from $0.02 per basic share in the fourth quarter of 2010.

During 2011, funds from operations increased by 208 percent to $57.8 million compared to $18.8 million in the same period of 2010. On a per share basis, funds from operations increased by 96 percent to $1.00 per basic share during 2011 from $0.51 per basic share in the same period of 2010.

Funds from operations per share increased by 44 percent to $0.36 in the fourth quarter from $0.25 in the third quarter of 2011. Funds from operations increased by 58 percent to $22.1 million in the fourth quarter from $14.0 million in the third quarter of 2011.

Cash flow from operations differs from funds from operations due to the inclusion of changes in non-cash working capital, as well as non-recurring recapitalization costs. Cash flow from operations for the three months ended December 31, 2011, was $19.0 million as compared to $0.6 million in the same period of 2010.

Included in cash flow from operations is a decrease in non-cash working capital of $3.1 million in the fourth quarter of 2011 and a decrease of $0.4 million from the same period in 2010.

Cash flow from operations for 2011 was $56.6 million as compared to $16.1 million in the same period of 2010. Included in cash flow from operations is a decrease in non-cash working capital of $1.2 million during 2011 and a decrease of $2.7 million from the same period in 2010.

Funds from Operations

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per share and per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Funds from operations	**22,088**	977	2,161%	**57,789**	18,764	208%
Per share - basic ($)	**0.36**	0.02	1,700%	**1.00**	0.51	96%
Per share - diluted ($)	**0.35**	0.02	1,650%	**0.98**	0.51	92%
$ per boe	**31.95**	2.65	1,106%	**26.57**	16.99	56%
Cash flow from operations	**19,022**	594	3,102%	**56,639**	16,128	251%

STOCK-BASED COMPENSATION

Surge recorded net stock-based compensation expense of $1.1 million during the three months ended December 31, 2011, compared to $0.7 million for the same period of 2010, calculated using the Black-Scholes option-pricing model.

Surge recorded net stock-based compensation expense of $3.5 million during 2011, compared to $5.4 million for the same period of 2010, calculated using the Black-Scholes option-pricing model. The decrease from the comparative period expense was due to the 2010 recapitalization.

During 2011, 2,355,500 options were issued at a weighted average exercise price of $8.92 per option and 43,000 options were forfeited at a weighted average price of $5.96 per option.

The following assumptions were used to calculate stock-based compensation during 2011: zero dividend yield; expected volatility of 69 percent; risk free rate of two percent; and expected life of five years.

Stock-based compensation

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Stock-based compensation	**2,635**	1,288	105%	**8,315**	3,106	168%
Stock-based compensation on performance warrants	**-**	-	-	**-**	4,912	(100%)
Stock-based compensation on flow-through share premiums	**-**	-	-	**-**	331	(100%)
Capitalized stock-based compensation	**(1,575)**	(608)	159%	**(4,853)**	(2,998)	62%
Net stock-based compensation	**1,060**	680	56%	**3,462**	5,351	(35%)
Net stock-based compensation $ per boe	**1.53**	1.85	(17%)	**1.59**	4.85	(67%)

DEPLETION AND DEPRECIATION

Depletion and depreciation are calculated based upon capital expenditures, production rates and proved plus probable reserves. Excluded from the Corporation's depletion and depreciation calculation are costs associated with salvage values of $27.0 million. Future development costs for proved and probable reserves of $140.1 million have been included in the depletion calculation.

Surge recorded $21.6 million or $31.25 per boe in depletion and depreciation expense during the three months ended December 31, 2011, as compared to $19.12 per boe in depletion and depreciation expense in the same period of 2010. This increase is due to a $9.0 million impairment of a south-east Alberta CGU, which is primarily due to a decrease in gas prices.

Surge recorded $48.5 million or $22.29 per boe in depletion and depreciation expense during 2011, as compared to $17.20 per boe in depletion and depreciation expense in the same period of 2010.

Depletion expense, excluding the impact of the $9 million impairment, would have been $18.23 per boe for the three months ended December 31, 2011 and $18.15 per boe for the year ended December 31, 2011.

The depletion and depreciation calculation is based on production volumes of 7,154 boe for the quarter. This increase in the depletion and depreciation expense per boe is due to the corporate and property acquisitions completed during the previous year, as well as a 88 percent increase in production, as well as the aforementioned impairment.

Depletion and Depreciation Expense

	Three Months Ended December 31,			Years Ended December 31,		
($000s except per boe)	**2011**	2010	% Change	**2011**	2010	% Change
Depletion and depreciation expense	**21,604**	7,045	207%	**48,491**	18,992	155%
$ per boe	**31.25**	19.12	63%	**22.29**	17.20	30%

NET INCOME (LOSS)

The Corporation recorded a net loss for the three months ended December 31, 2011 of $5.5 million or $0.09 per basic share, compared to a net loss of $4.0 million or $0.08 per basic share for the same period of 2010. During 2011, the Corporation recorded a net income of $2.1 million or $0.04 per basic share, compared to a net loss of $7.7 million or $0.21 per basic share for the year ended December 31, 2010.

Net income excluding the impact of the $9 million impairment would have been approximately $1.2 million for the three months ended December 31, 2011 and approximately $8.8 million for the year ended December 31, 2011.

Net Income (Loss)

($000s except per share)	Three Months Ended December 31, 2011	2010	% Change	Years Ended December 31, 2011	2010	% Change
Total	**(5,531)**	(3,999)	(38%)	**2,095**	(7,695)	nm
Per share - basic ($)	**(0.09)**	(0.08)	(13%)	**0.04**	(0.21)	nm
Per share - diluted ($)	**(0.09)**	(0.08)	(13%)	**0.04**	(0.21)	nm

CASH-BASED CAPITAL EXPENDITURES

During 2011, Surge invested a total of $165.2 million net of property dispositions. Surge invested $91.6 million, net of $1.9 million in Alberta drilling royalty credits, to drill and complete 38 gross (35.36 net) wells and frac four existing vertical wells.

In addition, Surge invested $29.2 million in facilities, pipeline, and equipment, $23.4 million in seismic and land acquisitions, $24.9 million in property acquisitions, and $6.2 million on other capital items. Surge disposed of certain oil and gas properties for proceeds of $9.8 million.

Cash-Based Capital Expenditure Summary

($000s)	Q1 2011	Q2 2011	Q3 2011	Q4 2011	2011	2010	Change
Land	4,568	1,828	10,301	6,687	23,384	3,547	559%
Seismic	56	476	658	421	1,611	2,330	(31%)
Drilling and completions	20,494	5,344	31,894	31,952	89,684	28,880	211%
Facilities, equipment and pipelines	8,354	3,526	8,400	8,963	29,243	4,882	499%
Acquisitions	11,333	13,576	-	-	24,909	77,783	(68%)
Other	1,496	1,919	719	2,042	6,175	77,783	(92%)
Total exploration and development	46,301	26,669	51,972	50,065	175,006	195,205	(10%)
Property dispositions	(1,301)	(5,224)	-	(3,323)	(9,848)	119,779	(108%)
Total	45,000	21,445	51,972	46,742	165,158	314,984	(48%)

Quarterly and Annual Financial Information

	IFRS Q4 2011	IFRS Q3 2011	IFRS Q2 2011	IFRS Q1 2011	IFRS Year end 2010
Oil, Natural gas & NGL sales	**42,812**	33,012	29,796	25,872	57,927
Net earnings (loss)	**(5,531)**	4,811	3,317	(502)	(7,695)
Net earnings (loss) per share ($):					
Basic	**(0.09)**	0.09	0.06	(0.01)	(0.21)
Diluted	**(0.09)**	0.08	0.06	(0.01)	(0.21)
Total assets	**516,062**	-	-	-	378,544
Total long-term financial liabilities	**72,197**	-	-	-	30,000
Average daily sales					
Oil & NGL (bbls/d)	**4,534**	3,781	2,995	3,090	1,871
Natural gas (mcf/d)	**17,885**	14,313	12,334	11,915	6,930
Barrels of oil equivalent (boe per day) (6:1)	**7,514**	6,166	5,051	5,076	3,026
Average sales price					
Natural gas ($/mcf)	**3.49**	3.81	4.13	3.88	3.96
Oil & NGL ($/bbl)	**88.60**	80.29	92.36	77.86	69.83
Barrels of oil equivalent ($/boe)	**61.93**	58.19	64.83	56.64	52.45

Quarterly and Annual Financial Information

	IFRS Q4 2010	IFRS Q3 2010	IFRS Q2 2010	IFRS Q1 2010	CGAAP Year end 2009
Oil, Natural gas & NGL sales	18,544	14,264	11,141	13,978	42,853
Net earnings (loss)	(3,999)	664	(7,109)	2,749	(2,112)
Net earnings (loss) per share ($):					
Basic	(0.08)	0.02	(0.26)	0.15	(0.13)
Diluted	(0.08)	0.02	(0.26)	0.14	(0.13)
Total assets	-	-	-	-	132,360
Total long-term financial liabilities	-	-	-	-	41,650
Average daily sales					
Oil & NGL (bbls/d)	2,308	1,841	1,621	1,707	1,477
Natural gas (mcf/d)	10,182	7,783	3,823	5,874	6,995
Barrels of oil equivalent (boe per day) (6:1)	4,005	3,138	2,258	2,686	2,643
Average sales price					
Natural gas ($/mcf)	3.55	3.71	3.74	5.20	4.85
Oil & NGL ($/bbl)	70.70	69.33	66.57	72.35	58.84
Barrels of oil equivalent ($/boe)	50.33	49.41	54.22	57.83	45.32

Share Capital and Option Activity

	IFRS **Q4 2011**	*IFRS* **Q3 2011**	*IFRS* Q2 2011	*IFRS* Q1 2011	*IFRS* Q4 2010	*IFRS* Q3 2010	*IFRS* Q2 2010	*IFRS* Q1 2010
Weighted Common Shares	**62,124,542**	56,118,838	56,098,181	56,094,747	53,065,155	30,874,642	27,589,374	18,576,487
Stock option dilution (treasury method)[1]	**1,189,529**	1,348,828	1,187,618	-	-	-	-	457,033
Weighted average dilution shares oustanding[1]	**63,314,071**	57,467,666	57,285,799	56,094,747	53,065,155	30,874,642	27,589,374	19,033,520

[1] In computing the net income per diluted share in the current period, 1,189,529 shares were added to the weighted average number of shares outstanding.

On March 21, 2012 Surge had 71,032,967 common shares, 2,069,319 performance warrants and 4,984,999 options outstanding.

LIQUIDITY AND CAPITAL RESOURCES

Subsequent to December 31, 2011, Surge increased its bank line from $150 million to $175 million.

On December 31, 2011, Surge had net debt of $97.2 million and a net working capital deficit including bank debt of $99.4 million, including the financial contract liability of $2.2 million. Surge maintained approximately $52.8 million of borrowing capacity at year-end, giving Surge considerable financial flexibility as it enters 2012. Surge's ratio of year end net debt to fourth quarter 2011 annualized cash flow was 1.1 to 1.

Surge anticipates that future capital requirements will be funded through a combination of internal cash flow, divestitures, debt and/or equity financing. Furthermore, Surge's flexible capital program and unused bank line further add to Surge's ability to fund future capital requirements. There is no assurance that debt and equity financing will be available on terms acceptable to the Corporation to meet its capital requirements.

The Corporation defines net debt as outstanding bank debt plus or minus cash-based working capital excluding the fair value of financial contracts as follows:

Net Debt

($000s)		
Bank debt	$	(72,197)
Accounts receivable		19,512
Prepaid expenses and deposits		4,948
Accounts payable and accrued liabilities		(49,467)
Total	**$**	**(97,204)**

As at December 31, 2011 The Corporation has a $150 million extendible, revolving term credit facility with a syndicate of Canadian banks bearing interest at bank rates. The facility is available on a revolving basis until May 5, 2012. On May 5, 2012, at the Corporation's discretion, the facility is available on a non-revolving basis for a one-year period, at the end of which time the facility would be due and payable. Alternatively, the facilities may be extended for a further 364-day period at the request of the Corporation and subject to the approval of the syndicate. As the available lending limits of the facilities are based on the syndicate's interpretation of the Corporation's reserves and future commodity prices, there can be no assurance that the amount of the available facilities will not decrease at the next scheduled review. Interest rates vary depending on the ratio of net debt to cash flow. The facility had an effective interest rate of prime plus 2.75 percent as at December 31, 2011 (December 31, 2010 – prime plus 1.50 percent).

Surge's facility is secured by a general assignment of book debts, debentures of $200.0 million with a floating charge over all assets of the Corporation with a negative pledge and undertaking to provide fixed charges on the major producing petroleum and natural gas properties at the request of the bank.

RELATED-PARTY AND OFF-BALANCE-SHEET TRANSACTIONS

Surge was not involved in any off-balance-sheet transactions or related party transactions during the three months and year ended December 31, 2011.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Corporation has entered into farm-in agreements in the normal course of its business. The Corporation is also contractually obligated under its debt agreements as outlined under liquidity and capital resources.

Surge has future minimum payments relating to its operating leases and firm transportation agreements totalling $9.3 million, as summarized below:

Commitments

($000s)		
2012	$	2,256
2013		1,912
2014		1,622
2015		1,410
2016		909
2017+		1,204
Total	**$**	**9,313**

Financial instruments

Derivative contracts are recorded at fair value based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. The actual amounts received or paid to settle these instruments at maturity could differ significantly from those estimated.

The following table outlines the realized and unrealized losses on interest rate contracts for the year ended December 31, 2011:

					Year ended December 31, 2011	
Term	Type (floating to fixed)	Amount (C$)	Company Fixed Interest Rate (%) (1)	Counter party Floating Rate Index	Unrealized loss ($000s CDN)	Realized loss ($000s CDN)
Jan 1, 2012 to Dec 31, 2014	Swap	$ 50,000,000	2.74%	CAD-BA-CDOR	(2,467)	-

(1) *The interest rate hedge is comprised of a range, beginning at 1.439% and escalating quarterly to a maximum of 3.952%.*

The following table outlines the realized and unrealized gains (losses) on oil and gas commodity contracts and in for the year ended December 31, 2011:

Term	Type (floating to fixed)	Volume	Swap Price (Surge receives) (C$)	Index (Surge pays) (C$)	Year ended Dec 31, 2011 Unrealized gains (losses) ($000s CDN)	Realized gains (losses) ($000s CDN)
Jan 1 to Dec 31, 2011	Call	500 GJs/d	$ 6.55	AECO Monthly Avg	1	-
Jan 1 to Dec 31, 2011	Put	500 GJs/d	$ 5.00	AECO Monthly Avg	(233)	277
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	1,247	(1,278)
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$ 96.55	WTI - NYMEX	(415)	166
Jan 1 to Dec 31, 2011	Call	125 bbls/d	$ 78.40	WTI - NYMEX	757	(712)
Jan 1 to Dec 31, 2011	Put	250 bbls/d	$ 78.40	WTI - NYMEX	(123)	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 85.50	WTI - NYMEX	749	(531)
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	1,247	(1,278)
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$ 91.00	WTI - NYMEX	(659)	416
Apr 1 to Dec 31, 2011	Call	250 bbls/d	$ 84.35	WTI - NYMEX	-	689
Apr 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	-	(988)
Jul 1 to Dec 31, 2011	Call	65 bbls/d	$ 90.00	WTI - NYMEX	-	(47)
Jul 1 to Dec 31, 2011	Put	250 bbls/d	$ 90.00	WTI - NYMEX	-	87
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	$ 97.00	WTI - NYMEX	(346)	-
Jan 1 to Dec 31, 2012	Call	63 bbls/d	$ 80.00	WTI - NYMEX	(524)	-
Jan 1 to Dec 31, 2012	Put	250 bbls/d	$ 80.00	WTI - NYMEX	206	-
Jan 1 to Dec 31, 2012	Call	250 bbls/d	$ 89.95	WTI - NYMEX	1,377	-
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	(1,891)	-
Jan 1 to Dec 31, 2012	Put	250 bbls/d	$ 90.00	WTI - NYMEX	391	-
Jan 1 to Dec 31, 2012	Call	93 bbls/d	$ 90.00	WTI - NYMEX	(508)	-
Jan 1 to Dec 31, 2012	Put	500 bbls/d	$ 90.00	WTI - NYMEX	783	-
Jan 1 to Dec 31, 2012	Call	158 bbls/d	$ 90.00	WTI - NYMEX	(865)	-
Jan 1 to Dec 31, 2012	Call	500 bbls/d	$ 96.00	WTI - NYMEX	1,960	-
Jan 1 to Dec 31, 2012	Swap	500 bbls/d	$ 85.00	WTI - NYMEX	(2,873)	-
Jan 1 to Dec 31, 2013	Call	250 bbls/d	$ 98.00	WTI - NYMEX	(8)	-
Jan 1 to Dec 31, 2013	Swap	250 bbls/d	$ 85.00	WTI - NYMEX	(277)	-
Total					**$ (4)**	**$ (3,199)**

Term	Type (floating to fixed)	Volume	Differential (Surge receives) (C$)	Index (Surge pays) (C$)	Year ended Dec 31, 2011 Unrealized gains (losses) ($000s CDN)	Realized gains (losses) ($000s CDN)
Jan 1 to Mar 31, 2012	Swap	500 bbls/d	$ 13.25	Western Canadian Select	102	-
Jan 1 to Jun 30, 2012	Swap	250 bbls/d	$ 14.85	Western Canadian Select	37	-
Oct 1 to Dec 31, 2011	Swap	250 bbls/d	$ 14.00	Western Canadian Select	-	(320)
Total					**$ 139**	**$ (320)**

1. SUBEQUENT EVENTS

(a) On January 6th, 2012 the Corporation acquired all of the outstanding shares of a private oil and gas company. As consideration, approximately 7.9 million common shares were issued at an approximate value of $71.3 million and a cash payment of $18.5 million was made. Furthermore, an approximate $14.4 million in working capital deficiency was acquired, for total consideration of approximately $104.2 million.

(b) Subsequent to the above acquisition, Surge's credit facility increased from $150 million at December 31, 2011 to $175 million.

(c) Subsequent to December 31, 2011, the Corporation entered into several financial oil contracts:

Term	Type	Volume	Swap price (C$) (Surge Receives)	Index (Surge pays) (C$)
Apr 1, 2012 - Dec 31, 2012	Swap	500bbls/d	101.50	WTI - NYMEX
Apr 1, 2012 - Dec 31, 2012	Swap	500bbls/d	90.00	WTI - NYMEX
Apr 1, 2012 - Dec 31, 2012	Call	500bbls/d	96.00	WTI - NYMEX
Jan 1, 2013 - Dec 31, 2013	Swap	250bbls/d	95.00	WTI - NYMEX
Jan 1, 2013 - Dec 31, 2013	Swap	250bbls/d	85.00	WTI - NYMEX
Jan 1, 2013 - Dec 31, 2013	Call	250bbls/d	95.00	WTI - NYMEX
Jan 1, 2013 - Mar 31, 2013	Swap	250bbls/d	104.85	WTI - NYMEX
Jan 1, 2013 - Mar 31, 2013	Swap	500bbls/d	95.00	WTI - NYMEX
Jan 1, 2013 - Mar 31, 2013	Call	315bbls/d	95.00	WTI - NYMEX
Apr 1, 2013 - Jun 30, 2013	Swap	250bbls/d	105.05	WTI - NYMEX
Apr 1, 2013 - Jun 30, 2013	Swap	500bbls/d	95.00	WTI - NYMEX
Apr 1, 2013 - Jun 30, 2013	Call	300bbls/d	95.00	WTI - NYMEX

CHANGE IN ACCOUNTING POLICIES

Adoption of International Financial Reporting Standards

The consolidated financial statements and comparative information has been prepared in accordance with International Financial Reporting Standards (IFRS). The Corporation adopted IFRS on January 1, 2011. Previously, Surge prepared its consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles (Canadian GAAP). The Corporation has provided IFRS accounting policies and reconciliations between Canadian GAAP and IFRS in note 3 and note 21 in its December 31, 2011 Consolidated Financial Statements.

IFRS 1 Exemptions

On transition to IFRS on January 1, 2010, Surge used certain exemptions allowed under IFRS 1 – *First Time Adoption of International Reporting Standards*.

Impact of Transition to IFRS

(a) IFRS 1 election for full cost oil and gas entities

The Corporation elected to use an IFRS 1 exemption whereby the previous GAAP full cost pool was used to measure exploration and evaluation assets and development and production assets on transition to IFRS as follows:

(i) exploration and evaluation assets were reclassified from the full cost pool to intangible exploration and evaluation assets at the amount that was recorded under previous GAAP; and

(ii) the remaining full cost pool was allocated to the producing/development and respective CGU's assets and components pro rata using reserve values.

As at December 31, 2010, the transfer was $67.9 million which included undeveloped land acquired in 2010 net of expiries as well as additional unproved interests acquired through corporate and asset acquisitions in 2010.

(b) Impairment of property, plant and equipment ("PP&E")

In accordance with IFRS, impairment tests of PP&E must be performed at the CGU level as opposed to the entire PP&E balance which was required under the previous GAAP through the full cost ceiling test. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. For Surge, the recoverable amount is determined using fair value less cost to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. There was no impairment to PP&E on transition as of January 1, 2010.

For the year ended December 31, 2010, as a result of decreased forward natural gas prices which impacted the fair value less costs to sell derived from the Corporation's reserves, an impairment charge of $1.2 million was recognized as additional depletion and depreciation expense.

PP&E impairments can be reversed in the future if the recoverable amount increases.

(c) Decommissioning obligations

Under the previous GAAP asset retirement obligations were discounted at a credit adjusted risk free rate of eight to nine percent. Under IFRS the estimated cash flows to abandon and remediate the wells and facilities has been risk adjusted therefore the provision is discounted at the risk free rate of approximately three to four percent in effect at the end of each reporting period. The change in the decommissioning obligations each period as a result of changes in the discount rate will result in an offsetting charge to PP&E. Upon transition to IFRS the impact of this change was a $5.8 million increase in the decommissioning obligations with a corresponding decrease to retained earnings on the statement of financial position.

As at December 31, 2010 the decommissioning obligations were $16.6 million higher than under the previous GAAP due to the change in discount rate and its impact on the liabilities incurred or acquired during 2010.

As a result of the change in the discount rate, the decommissioning obligation accretion expense increased $0.1 million during the year ended December 31, 2010 as the lower discount rate only partially offset the impact of the higher obligation. In addition, under the previous GAAP accretion of the discount was included in depletion and depreciation expense. Under IFRS it is included in finance expenses.

(d) Depletion policy

Upon transition to IFRS, the Corporation adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under the previous GAAP was based on units of production over proved reserves. In addition, depletion was done on a single Canadian cost center under the previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (ie. fields or combinations thereof).

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election, as discussed in note (a) above.

For the three months ended December 31, 2010, depleting the oil and natural gas interests over proved plus probable reserves resulted in a decrease to depletion and depreciation of $1.4 million. For the year ended December 31, 2010 depletion and depreciation was reduced by $4.7 million as a result of changes to the depletion calculation, including the impact of $1.2 million of impairment.

(e) Business combinations

In accordance with IFRS, internal transaction costs incurred on a business combination are expensed. Under the previous GAAP, these costs were capitalized as part of the acquisition. As a result, $1.0 million was charged to Transaction Costs for transaction costs incurred on the Corinthian Acquisition during the year ended December 31, 2010. The purchase price was reduced by $8.7 million due to the re-valuation of common shares based on the change in the valuation date to the closing date rather than announcement date; however this was offset by a $8.8 million increase in the valuation of the decommissioning liability under IFRS.

(f) Deferred income taxes

The adjustment to deferred income taxes on transition relates to the opening adjustment to the decommissioning obligations. The opening adjustment for the decommissioning obligations was charged through retained earnings on the statement of financial position thereby creating a temporary difference on the liability. The deferred income tax impact of the opening adjustment was a deferred income tax asset of $1.4 million.

The deferred income tax impact of the December 31, 2010 adjustment was a deferred income tax asset of $5.2 million.

Under IFRS there is no requirement to separate the portion of deferred income taxes related to current assets or liabilities. Adjustments to deferred income taxes have been made in regards to the adjustment noted above that resulted in a change to the temporary difference between tax and accounting values.

(g) Finance expenses

Under IFRS a separate line item is required in the statement of income and comprehensive income for finance expenses. The items under the previous GAAP that were reclassified to finance expenses were interest and accretion expense, which included the accretion on the decommissioning obligations.

(h) Flow through shares

Under IFRS, the premium received for a flow through share in excess of the average share price is required to be shown as a liability on the statement of financial position. Under the previous GAAP, the premium was recognized in share capital. Under IFRS, the flow through share premium is recognized as a reduction to deferred tax expense in the statement of income. In addition, the tax costs of issuing the flow through shares related to the foregone tax attributes is recognized as a deferred tax expense as the expenditures under the flow through are incurred. The impact of the opening adjustment was an increase to share capital of $2.0 million and a liability for $0.3 million representing the premium on the December 2009 flow through share issuance that related to amounts unexpended at the date of transition and December 31, 2010.

(i) Cashflow impact

The transaction costs incurred on the Corinthian acquisition was classified under investing activities under previous GAAP, however under IFRS, it is classified as operating activity. There were no changes to financing activities.

(j) Future Accounting Changes

The following pronouncements from the IASB will become effective for financial reporting periods beginning on or after January 1, 2013 and have not yet been adopted by the Corporation. All of these new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application:

- IFRS 9 - Financial Instruments addresses the classification and measurement of financial assets.
- IFRS 10 - Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.
- IFRS 11 - Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.
- IFRS 12 Disclosure of Interest in Other Entities provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.
- IFRS 13 - Fair Value Measurement defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.
- IAS 27 - Separate Financial Statements revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.
- IAS 28 - Investments in Associate and Joint Ventures revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The Corporation has not completed its evaluation of the effect of adopting these standards on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of decommissioning liabilities and the application of impairment tests.

Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, assess impairment and determine the change in fair value of financial contracts.

Management's estimates of prices are based on the price forecast from our reserve engineers and the current forward market.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (''NI 51-101'') and (b) future prices of oil and gas.

Decommissioning Liability

Management calculates the decommissioning liability based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life. There are uncertainties related to decommissioning liabilities and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserve estimates, costs and technology

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The President and Chief Executive Officer and Chief Financial Officer are responsible for designing internal controls over financial reporting ("ICFR") or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Committee of Sponsoring Organizations of the Treadway Commision ("COSO") framework provides the basis for management's design of internal controls over financial reporting. Management and the Board work to mitigate the risk of a material misstatement in financial reporting; however, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met and it should not be expected that the disclosure and internal control procedures will prevent all errors or fraud.

It should be noted that while these controls and procedures have been put in place in the Company as of December 31, 2011, there was no requirement to test and evaluate the effectiveness of these controls based on the Company previously being TSX Venture Exchange listed up until October 21, 2011 when the Company obtained a listing on the Toronto Stock Exchange.

RISK FACTORS

Additional risk factors can be found under “Risk Factors” in the Corporation’s 2010 Annual Information Form, which can be found on www.sedar.com. Many risks are discussed below and in the 2010 Annual Information Form, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from forecast results.

On October 25, 2007, the Alberta Government announced the New Royalty Framework (NRF) which took after January 1, 2009. On March 3, 2009, the Alberta Government announced a drilling royalty credit and new well incentive program that will be in effect from April 1, 2009 to March 31, 2010. On November 29, 2008, the Alberta Government announced that in response to the global economic crisis and a slowdown in oil and natural gas drilling in Alberta, companies drilling certain new wells after November 19, 2008 have a one-time option of selecting a transitional rate or the NRF rate. All wells drilled between 2009 and 2013 that adopt the transitional rate will required to shift to the NRF on January 1, 2014. All wells drilled prior to November 19, 2008 will move to the NRF on January 1, 2009.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Surge depends on its ability to find, acquire, develop, and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Surge’s reserves will depend not only on the Corporation’s ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Surge.

Surge’s principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Corporation’s need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. Surge anticipates that future capital requirements will be funded through a combination of internal funds from operations, debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Corporation to meet its capital requirements. If any components of the Corporation’s business plan are missing, the Corporation may not be able to execute the entire business plan.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to governments and third parties and may require Surge’s operating entities to incur costs to remedy such discharge. Although Surge believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environment laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Surge’s financial condition, results of operations or prospects.

Surge’s involvement in the exploration for and development of oil and natural gas properties may result in Surge becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although, prior to drilling, Surge will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liability. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, Surge may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Surge. The occurrence of a significant event that was not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Surge's financial position, results of operations or prospects and will reduce income otherwise used to fund operations.

The Corporation utilizes financial derivatives contracts to manage market risk. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.