AR
10

Early Identification
Capture
Cost Effective Exploitation of
High Impact Oil Resource Plays

SURGE ENERGY INC

Positioned for light oil **growth**

FINANCIAL AND OPERATING SUMMARY

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Financial highlights						
Oil and NGL sales	**15,014**	9,999	50%	**47,685**	30,697	55%
Natural gas sales	**3,322**	2,934	13%	**10,029**	12,156	(17%)
Other revenue	**208**	-	nm	**213**	-	nm
Total oil, natural gas, and NGL revenue	**18,544**	12,933	43%	**57,927**	42,853	35%
Funds from operations[1]	**7,907**	5,320	49%	**25,688**	17,492	47%
Per share basic and diluted ($)	**0.15**	0.32	(53%)	**0.70**	1.05	(33%)
Net loss excluding non-recurring charges relating to the recapitalization[2]	**(4,147)**	(21)	nm	**(1,307)**	(2,112)	(38%)
Net earning (loss)	**(4,147)**	(21)	nm	**(10,326)**	(2,112)	389%
Per share basic and diluted ($)	**(0.08)**	-	nm	**(0.28)**	(0.13)	115%
Corporate & asset acquisitions (cash and share consideration)[3]	**66,239**	-	nm	**188,812**	-	nm
Capital expenditures	**26,465**	5,154	414%	**41,996**	17,888	135%
Net debt at end of period[4]	**46,240**	46,902	3%	**46,240**	46,902	3%
Operating highlights						
Production:						
Oil and NGL (bbls per day)	**2,308**	1,614	43%	**1,871**	1,477	27%
Natural gas (mcf per day)	**10,182**	6,887	48%	**6,930**	6,995	(1%)
Total (boe per day) (6:1)	**4,005**	2,762	45%	**3,026**	2,643	14%
Average realized price (excluding hedges):						
Oil and NGL ($per bbl)	**70.70**	67.35	5%	**69.83**	56.93	23%
Natural gas ($ per mcf)	**3.55**	4.63	(23%)	**3.96**	4.76	(17%)
Realized gain (loss) on commodity contracts ($ per boe)	**1.92**	0.54	256%	**2.53**	0.90	181%
Netback (excluding hedges) ($ per boe):						
Oil, natural gas and NGL sales	**50.33**	50.90	(1%)	**52.45**	44.42	18%
Royalties	**(6.43)**	(5.77)	11%	**(7.35)**	(5.23)	41%
Operating expenses	**(14.87)**	(15.60)	(5%)	**(15.25)**	(13.52)	13%
Transporation expenses	**(1.72)**	(1.84)	(7%)	**(2.20)**	(2.03)	8%
Operating netback	**27.31**	27.69	(1%)	**27.65**	23.64	17%
G&A expenses	**(5.96)**	(4.32)	38%	**(5.60)**	(4.03)	39%
Interest expense	**(0.80)**	(2.37)	(66%)	**(0.90)**	(2.11)	(57%)
Corporate netback	**20.55**	21.00	(2%)	**21.15**	17.50	21%

(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 Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other entities.

(2) Excluding the non-recurring recapitalization costs, as well as the increase in stock-based compensation that resulted from the recapitalization. Please see net income (loss) note.

(3) Please see capital expenditures note.

(4) The Corporation defines net debt as outstanding bank debt plus or minus cash-based working capital.

ABOUT SURGE

Surge Energy Inc. ("Surge" or "the Corporation") is a light oil focused energy production company with four core areas of operations throughout Alberta and South West Manitoba/North Dakota. The Company is focused on building shareholder value by growing per share production, cash flow and reserves. Upon the closing of Surge's most recently announced acquisition, expected on May 12, 2011, the Corporation will have: a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP(1) of more than 460 million barrels (gross) and more than 460 (350 net) oil drilling locations comprised of 85 percent light oil, with the remainder of the inventory being medium gravity oil.

Surge's business strategy is as follows:

- Target per share growth by the early identification, capture and cost effective exploitation of high impact oil resource plays

- Position Surge in early stage oil resource plays that include the following key criteria:
  - Significant oil in place per section and low recovery factor to date.
  - Vertical well control for predicting horizontal multi-frac production performance.
  - Significant undeveloped land.
  - Available infrastructure.
  - Operatorship and all-season access.
  - Compelling economics.
- Apply the Corporation's proven expertise and experience to build core areas which can deliver top quartile corporate performance

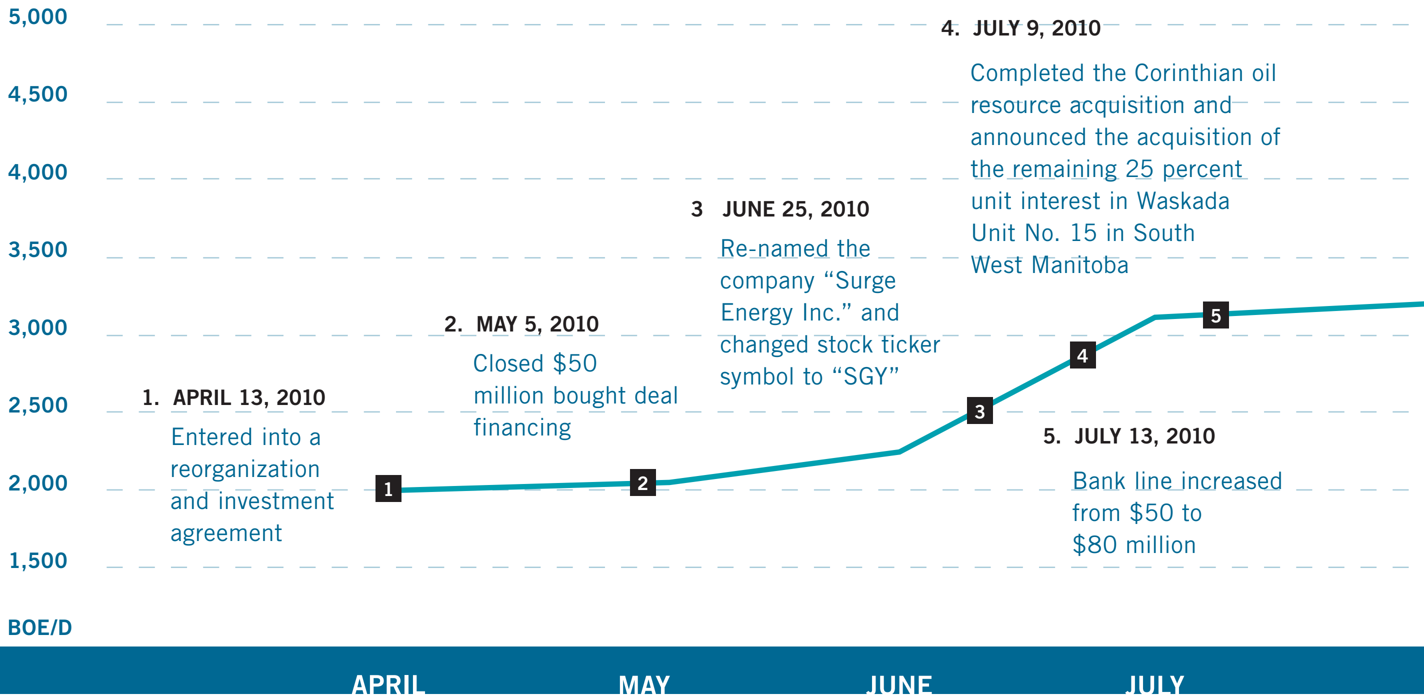
Maintaining financial and operational flexibility is a key element in Surge's business model. Surge's 2011 capital program is set at $98 million (excluding acquisitions and dispositions) with spending being allocated amongst the Corporation's four core operation areas. Surge will be flexible in its capital spending in order to be responsive to its environment, costs and capital markets.

Surge is pleased with its many achievements during the transformational year of 2010 and is optimistic about its future given its high quality asset base, large unbooked oil drilling inventory, financial position, solid netbacks and technical and financial professional expertise. Surge's common shares trade on the TSX Venture Exchange under the symbol "SGY." Surge looks forward to applying for listing of its common shares on the Toronto Stock Exchange in the fourth quarter of 2011.

(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 economically viable or technically feasible to produce any portion of this DPIIP except for those identified as proved or probable reserves. There is no certainty that it will be commercially viable to produce any portion of the resources.

CONTENTS

EARLY IDENTIFICATION, CAPTURE, AND COST EFFECTIVE



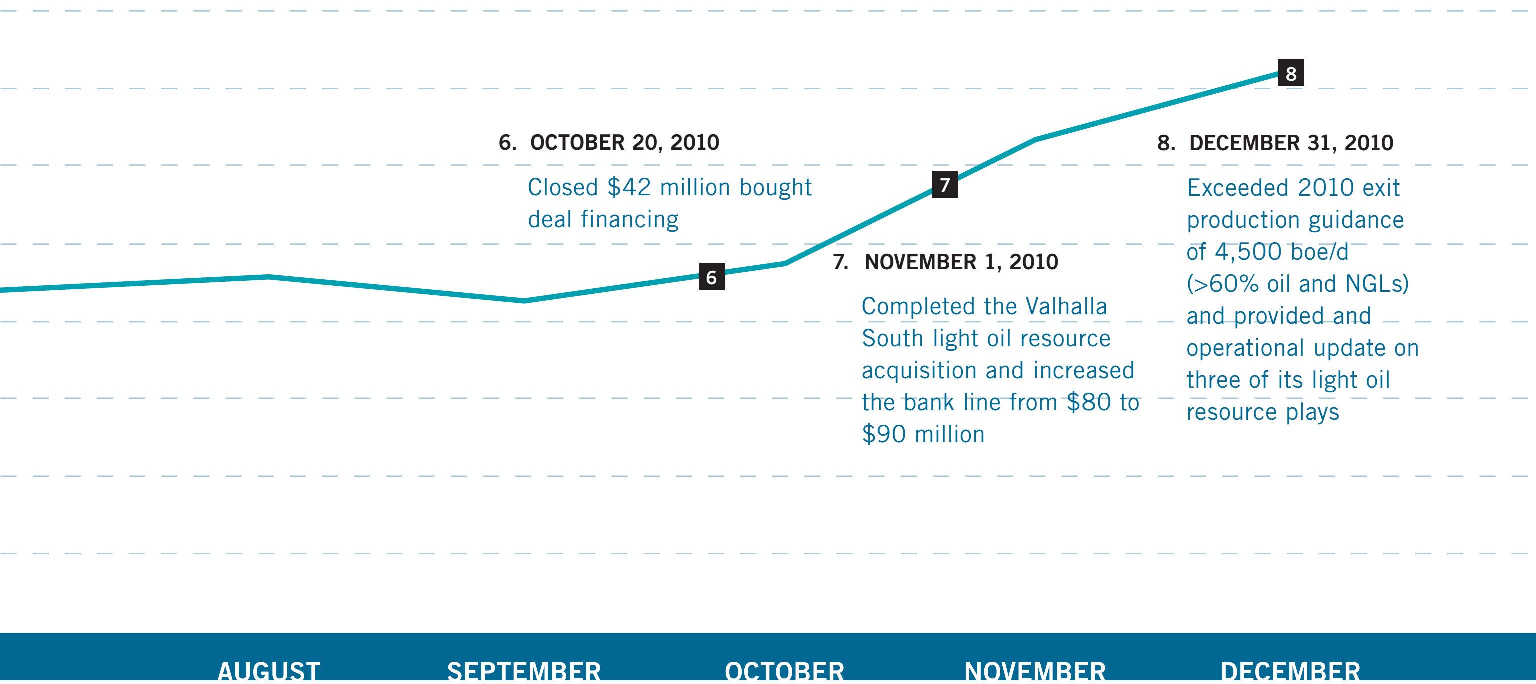
PRESIDENT'S LETTER

STRATEGY, EXECUTION, SUCCESS

We are delighted with Surge's transformation during 2010 since the recapitalization of Zapata Energy Corporation on April 13, 2010. Over this brief period, Surge completed two key transactions that positioned the Corporation for growth in three exciting new light oil resource plays at Valhalla South (Doig), Windfall (Bluesky) and South West Manitoba (Spearfish). Thanks to our talented team, we were able to commence drilling programs in these key light oil resource plays before the end of 2010. At year end 2010, Surge had compiled an inventory of more than 245 gross (220 net) oil drilling locations, increased internally estimated DPIIP to more than 300 million barrels (gross), increased Proved plus Probable reserves by 114 percent and achieved a year end exit production rate of more than 4,500 barrels of oil equivalent (boe) per day, a 125 percent increase from approximately 2,000 boe per day shortly after the recapitalization in April 2010.

During 2010, Surge built a strong platform for growth by recruiting 29 key employees and establishing four new teams: corporate development, exploration and two area asset teams. Our financial stability was also significantly improved by increasing our bank line from $50 million to $90 million during 2010 and maintaining a year end debt of only $46 million, excluding the fair value of financial contracts. Surge's profile was enhanced as a result of the Corporation's significant increase in analyst coverage (from zero to nine), trading liquidity and institutional shareholder base, which grew from virtually none to an estimated 65 percent.

EXPLOITATION OF HIGH IMPACT OIL RESOURCE PLAYS



DURING 2010, SURGE POSITIONED ITSELF IN THREE EXCITING NEW LIGHT OIL RESOURCE PLAYS

ACHIEVEMENTS, HIGHLIGHTS AND FORECAST

- Increased production by 125 percent from approximately 2,000 boe per day shortly after the recapitalization in April 2010 to a 2010 exit production rate of more than 4,500 boe per day with a forecast to exit 2011 at 7,500 boe per day, with oil and NGL weighting increasing from 60 percent to more than 70 percent.
- Realized an average production rate of 4,005 boe per day in the fourth quarter 2010, a 45 percent increase as compared to 2009 production rate of 2,762 boe per day with a forecast to grow exit production by 67 percent to 7,500 boe per day in 2011.
- Realized an average production rate of 3,026 boe per day for the year ended December 31, 2010, a 14 percent increase as compared to the 2009 production rate of 2,643 boe per day, with a forecast to grow production by 98 percent to an average of 6,000 boe per day in 2011.
- More than 80 percent of Surge's revenue resulted from oil and natural gas liquids production, with less than 20 percent derived from natural gas production.
- Increased Proved plus Probable reserves by 114 percent from 9.9 million boe at December 31 2009 to 21.2 million boe at December 31, 2010.

MORE THAN 80 PERCENT OF SURGE'S REVENUE RESULTED FROM OIL AND NATURAL GAS LIQUIDS PRODUCTION

- Increased the Net Present Value discounted at 10 percent Before Tax (NPV10 BT) of Proved plus Probable reserves by 90 percent from $217 million as at December 31, 2009 to $412 million(1) as at December 31, 2010.
- Achieved Proved plus Probable Finding and Development ("F&D") costs of $13.15 per boe, including a $24.0 million change in Future Development Capital ("FDC").
- Achieved a F&D recycle ratio for 2010 of 2.1 times.
- Attained a Proved plus Probable Reserve Life Index of 12.9 years based on the Corporation's estimated 2010 exit production rate of approximately 4,500 boe per day.
- Achieved a Proved plus Probable reserves replacement ratio of 11.2 based on the Corporation's estimated 2010 average production for the year of 3,026 boe per day.
- Achieved a 100 percent success rate drilling 10 gross (10 net) wells in the fourth quarter 2010; realized a gross success rate of 91 percent drilling by 22 gross (21.5 net) wells in 2010.
- Executed preparation for 2011 drilling program targeting light oil, which is projected to increase operating netbacks to approximately $47.00 by the fourth quarter of 2011 based on recent 2011 strip oil and gas prices and increase light/medium oil weighting to greater than 70 percent.
- Reduced operating expenses per boe by five percent and transportation expenses per boe by seven percent in the fourth quarter of 2010 as compared to the fourth quarter of 2009, with a forecast to reduce combined operating and transportation costs by 21 percent to $13.00 per boe in the fourth quarter of 2011.
- Increased Surge's operating netback by 17 percent for the year ended December 31, 2010 as compared to the year ended December 31, 2009 from $23.64 to $27.65 per boe. Surge's fourth quarter 2011 netback is forecast to be approximately $47.00 per boe based on recent 2011 strip oil and gas prices and as a result of the Corporation's increasing light oil weighting and decreasing costs in 2011.
- Increased funds from operations by 49 percent to $8.0 million in the fourth quarter of 2010 from $5.3 million in the fourth quarter of 2009. Increased funds from operations by 47 percent to $25.7 million in 2010 from $17.5 million in 2009 with a forecast to grow funds from operations by 189 percent to $75 million in 2011.

(1) The estimated values disclosed do not represent fair market value.

SURGE'S MANAGEMENT TEAM HAS A SIMPLE AND WELL DEFINED BUSINESS PLAN

BUSINESS STRATEGY

Surge's management team has a simple and well defined business strategy to achieve per share growth in production, cash flow and reserves. The business plan focuses on applying our proven expertise and experience to build core areas which can deliver top quartile corporate performance via the early identification, capture and cost-effective exploitation of high-impact oil resource plays. Our strategy includes the following principles:

- Significant oil in place and low recovery factor to date.
- Vertical well control for predicting horizontal multi-frac production performance.
- Significant undeveloped land.
- Available infrastructure.
- Operatorship and all-season access.
- Compelling economics.

This business strategy provides Surge with the flexibility to control our future and compete effectively for capital and assets throughout Western Canada and the Northern US.

CORPORATE GOVERNANCE

Surge's Board of Directors, working with the management team, strives to ensure that the Corporation's governance practices provide effective stewardship and efficient operations in the best interests of the shareholders. The Board, which functions independently of management, meets frequently to consider a wide range of issues affecting Surge, including strategic direction, reserves, financial performance, disclosure and compensation. The Board reviews strategic plans proposed by management, business risks facing the Corporation and management's assessment of those risks.

OUTLOOK

Surge's operational results in the first quarter 2011 have exceeded management's expectations. The Corporation continues to implement management's business plan of targeting per share growth by positioning the Corporation in high impact oil resource plays with significant oil in place and applying its proven expertise and experience to build core areas. Surge continues to demonstrate this ability with the recent announcement of its expansion into North Dakota, where the Corporation significantly strengthened its position in the Spearfish light oil resource play by adding 205 gross (120 net) light oil horizontal drilling locations on 6,000 net acres of highly prospective lands. Management estimates DPIIP to be approximately 125 million barrels (gross) within these lands.

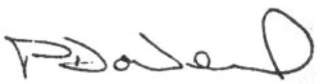
Complementing Surge's light oil resource plays at Valhalla South (Doig), Windfall (Bluesky) and South West Manitoba/North Dakota (Spearfish) are the low cost, low decline, high rate of return, crude oil assets in South East Alberta that have considerable secondary recovery potential. The infill drilling and secondary recovery programs that have been implemented to date provide significant internally generated cash flow and enable Surge to execute its capital program in each of its core areas.

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

In 2011, Surge will continue to grow the Corporation organically by drilling in each of its core areas, continuing the development of secondary recovery programs in South East Alberta and by evaluating plans for secondary recovery pilot programs on its new light oil resource plays. Additionally, the Corporation will continue to make accretive acquisitions that fit its business plan of positioning Surge in high impact, emerging crude oil resource plays. 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. Surge looks forward to applying for listing of its common shares on the Toronto Stock Exchange in the fourth quarter of 2011.

ACKNOWLEDGEMENTS

I would like to extend a sincere thanks to all Surge employees, management team and Board of Directors, who continue to work hard to implement the Corporation's business strategy and who have contributed to our success over the past eight months. I would also like to extend my thanks to Surge's shareholders for their support since our inception. Surge's success is your success, in 2010 and beyond.



Dan O'Neil
President & CEO

April 15, 2011

OPERATIONS REVIEW

SURGE OPERATING AREAS

2010 Exit Production:	>4,500 boe/d (60% light/medium oil and NGLs)
2011 Exit Production Guidance	>7,500 boe/d (>70% light/medium oil and NGLs)
Net Undeveloped Land:	>400,000 acres
Current Oil Drilling Locations:	>350 gross (>265 net): 100% oil

1. VALHALLA SOUTH, WESTERN ALBERTA

- Horizontal multi-frac light oil (40 degree API) resource play property targeting the Doig Formation.
- Operated property with an average of 82 percent working interest, all-season access and a net land position of approximately 8,600 acres.
- Up to 50 metres of gross pay in the Triassic Doig Formation.
- Located in North Western Alberta, approximately 40 kilometres west of Grande Prairie.
- Significant vertical well control, yielding lower risk inventory.
- Internally estimated discovered petroleum initially in place (DPIIP) of approximately 115 million barrels (mmbbls) gross.
- Average DPIIP per section of 16 mmbbls at a 0.1 millidarcies (mD) cutoff with an estimated current recovery factor of less than three percent.
- Internally estimated 25 gross (18.3 net) horizontal multi-frac development locations with only five gross (3.75 net) horizontal multi-frac locations booked.
- 3-D seismic covering entire pool.

2. WINDFALL, WESTERN ALBERTA

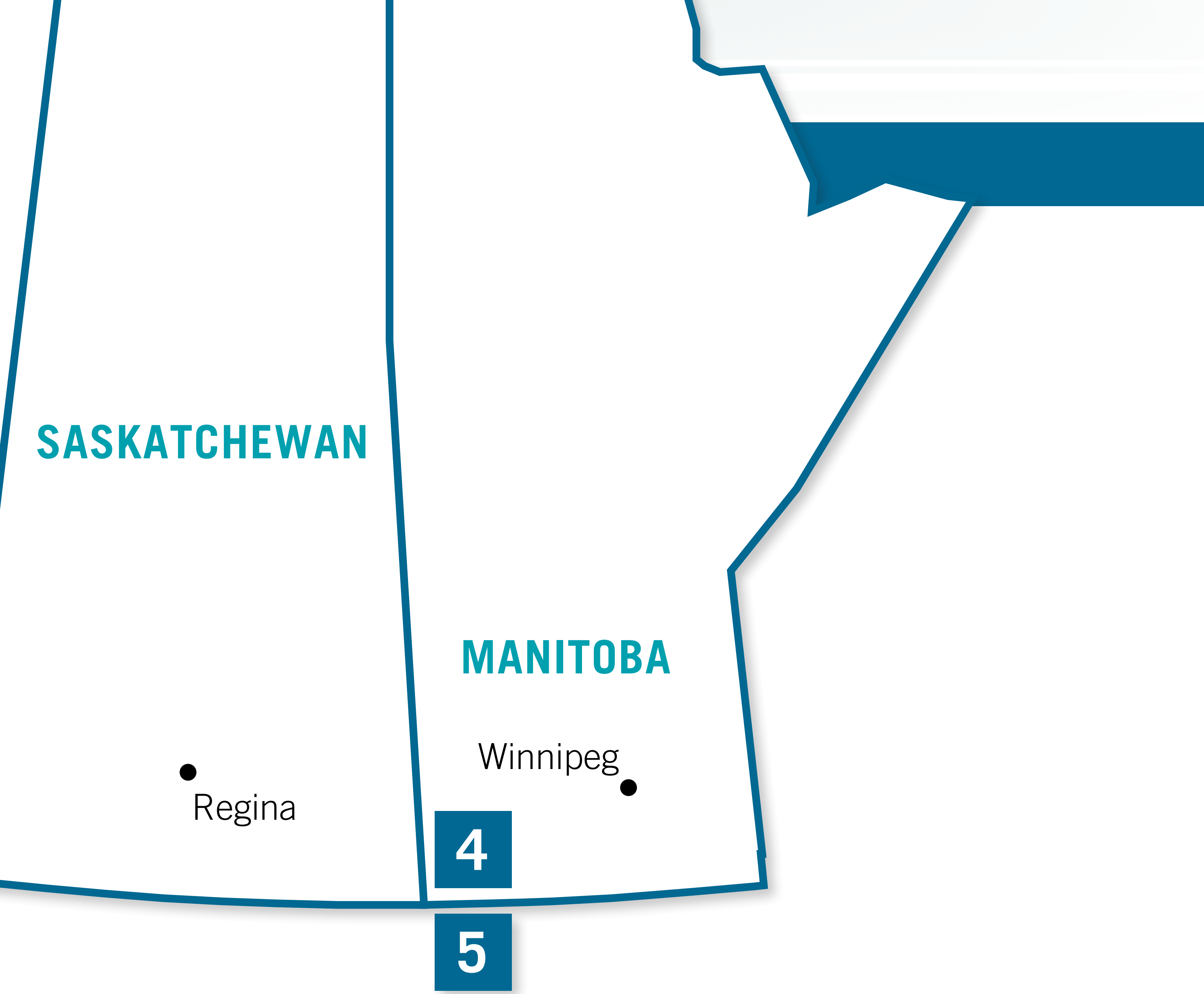
- Horizontal multi-frac light oil (36 degree API) resource play property targeting the Bluesky Formation.
- Operated property with an average working interest of 100 percent, all-season access and a net land. position of approximately 12,700 acres.
- Up to 16 metres of gross pay in the Bluesky light oil pool.
- Located in Western Alberta near Whitecourt.
- Vertical well control, yielding lower risk inventory.
- Internally estimated DPIIP of approximately 55 mmbbls (gross).
- Average DPIIP per section of 4.4 mmbbls at a 0.1 mD cutoff with an estimated current recovery factor of less than one percent.
- Internally estimated 28 gross (28 net) horizontal multi-frac development locations with only seven gross (seven net) horizontal multi-frac locations booked.
- The Corporation upgraded its battery facility and constructed additional flow lines during the first quarter of 2011.
- 3-D seismic data covering entire pool.

3. SILVER LAKE/SOUNDING LAKE/ GOOSEBERRY/LEELA, SOUTH EAST ALBERTA

- Multi-zone medium oil property (22-25 degree API).
- Operated and owned property with an average working interest of 90 percent on greater than 76,000 net acres of undeveloped land, recently expanded infrastructure and all-season access.
- Low decline rates of approximately 15 percent.
- Reliable, predictable, and stable oil production with significant enhanced oil recovery potential.
- Internally estimated DPIIP of approximately 26 mmbbls (gross).
- Potentially 2 to 5 mmbbls DPIIP per section at a 0.1 mD cutoff with an estimated recovery factor of less than five percent.
- Internally estimated 40 gross (40 net) development locations with 20 gross (20 net) locations booked.
- Operates seven oil batteries and an oil blending facility.

4. WASKADA/PIERSON/GOODLANDS, SOUTH WEST MANITOBA

- Horizontal multi-frac light oil (34 degree API) targeting the Lower Spearfish/Amaranth Formation.
- Operated property with 90 percent working interest, all-season access and a net land position of approximately 4,500 acres.
- Up to 35 metres of gross pay in the Spearfish/Lower Amaranth Formation.
- Located in South West Manitoba.
- Significant vertical well control, yielding lower risk inventory.
- Internally estimated DPIIP of approximately 76 mmbbls (gross) at Waskada.
- Average DPIIP per section of 15 mmbbls at a 0.1 mD cutoff with an estimated current recovery factor of less than one percent at Waskada.
- Internally estimated 124 gross (111 net) horizontal multi-frac development locations, primarily at Waskada with only 12 gross (12 net) horizontal multi-frac locations booked.



5. NORTH DAKOTA

- Horizontal multi-frac light oil (36 degree API).
- Approximately 6,000 net undeveloped acres of highly prospective lands for Spearfish development.
- Located adjacent to the Canada/US border.
- Internally estimated DPIIP of more than 125 mmbbls (gross) at a 0.1mD cutoff with an estimated current recovery factor of less than one percent.
- Internally estimated 205 gross (120 net) horizontal multi-frac development locations.
- Additional 100,000 net undeveloped acres that have potential for Spearfish, Basal Spearfish and Madison development.

SURGE CURRENTLY HAS AN INVENTORY OF MORE THAN 350 GROSS (265 NET) UNBOOKED, HIGH RATE OF RETURN OIL DRILLING LOCATIONS

DRILLING ACTIVITY

In 2010 Surge achieved a success rate of 86 percent drilling 22 (21.5 net) wells, resulting in a fourth quarter 2010 average production rate of 4,005 barrels of oil equivalent (boe) per day, an increase of 77 percent over the second quarter 2010 average production rate of 2,258 boe per day. The new management team recapitalized the Corporation during the second quarter of 2010. The 2010 capital program resulted in Proved plus Probable reserve growth of 114 percent.

	EXPLORATORY WELLS		DEVELOPMENT WELLS		TOTAL WELLS		SUCCESS RATE	
	GROSS	NET	GROSS	NET	GROSS	NET	NET	WI %
Valhalla South	-	-	-	-	-	-	-	-
Windfall	-	-	3	3	3	3	3	100%
Waskada	-	-	5	5	5	5	5	100%
SE Alberta & Other	2	2	12	11.5	14	13.5	11.5	85.19%
Total	2	2	20	19.5	22	21.5	19.5	91.00%

FUTURE DRILLING LOCATIONS

Surge currently has an inventory of more than 350 gross unbooked (265 net), high rate of return, oil drilling locations and will have more than 460 gross (350 net) oil drilling locations in inventory post the closing of the North Dakota acquisition expected for May 12, 2011. The table below outlines Surge's future drilling locations post the North Dakota acquisition expected for May 12, 2011:

PROPERTY	GROSS			NET		
	LOCATIONS	BOOKED	UNBOOKED	LOCATIONS	BOOKED	UNBOOKED
Valhalla South	25	5	20	18.3	3.8	14.6
South West Manitoba	124	12	112	111	12	99
North Dakota	205	0	205	120	0	120
Windfall	28	7	21	28	7	21
South East Alberta	72	27	45	70	25.3	44.7
Total	454	51	403	347.3	48.1	299.3

PRODUCTION

Surge's production since the recapitalization during the second quarter of 2010 is outlined on the following table:

	2010	2009	Q4 2010	Q3 2010	Q2 2010
Oil and NGLs (bbls per day)	1,871	1,475	2,308	1,841	1,621
Natural gas (mcf per day)	6,930	6,995	10,182	7,783	3,823
Total (boe per day)	3,026	2,641	4,005	3,138	2,258
% Oil and NGLs	62	56	58	59	72

SURGE HAS GROWN PRODUCTION IN EACH SUCCESSIVE QUARTER

Surge has grown production in each successive quarter since the recapitalization in April 2010. The fourth quarter 2010 average production rate of 4,005 boe per day represents an increase of 77 percent over the second quarter 2010 average production rate of 2,258 boe per day. Surge is forecasting a 2011 average production rate of 6,000 boe/d (greater than 70 percent light/medium oil and NGLs) and an exit production rate of 7,500 boe/d (greater than 70 percent light/medium oil and NGLs).

RESERVES

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, Sproule & Associates of Calgary, Alberta ("Sproule") prepared a reserves report (the "Sproule Report") that evaluated, as at December 31, 2010, the oil, natural gas liquids (NGLs) and natural gas reserves attributable to Surge's properties. The Sproule Report is dated February 25, 2011.

During 2010, Surge added 12.4 thousand barrels of oil equivalent (mboe) of high quality oil and gas Proved plus Probable reserves via total capital expenditures of approximately $231 million, which resulted in the following at year end 2010:

- Proved plus Probable reserves growth to 21.2 million boe, a 114 percent increase over year end 2009.
- Proved plus Probable oil and NGLs reserves growth to 12.4 million boe, a 112 percent increase over year end 2009.
- Proved plus Probable finding and development costs (F&D), including a $24 million change in Future Development Capital (FDC) of $13.15 per boe.
- A recycle ratio of 2.1 times based on a netback of $27.65 per boe and F&D costs of $13.15, including the $24.0 million change in FDC.
- Proved plus Probable Reserve Life Index of 12.9 years based on the Corporation's estimated 2010 exit production rate of approximately 4,500 boe per day.
- Proved plus Probable reserves replacement ratio of 11.2 based on the Corporation's estimated 2010 average production for the year of 3,026 boe per day.
- An estimated Net Asset Value (NAV) of $7.30 per basic share and $7.18 per fully diluted share at December 31, 2010 based on the net present value (discounted 10 percent before tax) value of Proved plus Probable reserves.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to the Corporation's properties and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND NATURAL GAS RESERVES – FORECAST PRICES AND COSTS

	GROSS RESERVES				NET RESERVES			
	LIGHT AND MEDIUM CRUDE OIL (MBBLS)	HEAVY CRUDE OIL (MBBLS)	NATURAL GAS LIQUIDS (MBBLS)	NATURAL GAS (MMCF)	LIGHT AND MEDIUM CRUDE OIL (MBBLS)	HEAVY CRUDE OIL (MBBLS)	NATURAL GAS LIQUIDS (MBBLS)	NATURAL GAS (MMCF)
Proved								
Developed Producing	2,624.3	1,924.5	388.3	19,992.0	2,263.6	1,585.9	259.9	17,920.0
Developed Non-Producing	526.2	44.4	138.8	6,859.0	447.1	37.6	92.6	5,868.0
Undeveloped	1,368.7	986.4	316.2	9,397.0	1,049.4	794.7	218.4	7,243.0
Total Proved	4,519.2	2,955.3	843.3	36,248.0	3,760.1	2,418.2	570.9	31,031.0
Probable	2,328.5	1,308.3	397.2	16,920.0	1,869.5	1,017.5	264.1	14,307.0
Total Proved plus Probable	6,847.7	4,263.6	1,240.5	53,168.0	5,629.6	3,435.7	835.0	45,338.0

(1) "Total Company Interest Reserves" are the Corporation’s working interest plus its royalty interest share of remaining reserves before the deduction of royalties.

(2) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share of remaining reserves before deduction of royalties and without including any royalty interests of the Corporation.

(3) "Net Reserves" are the Corporation's working interest (operating or non-operating) share of remaining reserves after deduction of royalty obligations, plus its royalty interests in reserves.

NET PRESENT VALUE OF FUTURE NET REVENUE – FORECAST PRICES AND COSTS

	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	297,142	235,164	197,284	171,364	152,433
Developed Non-Producing	52,483	41,752	34,497	29,306	25,422
Undeveloped	125,585	93,014	71,082	55,556	44,115
Total Proved	475,210	369,930	302,863	256,226	221,970
Probable	264,216	160,131	108,995	80,111	62,080
Total Proved plus Probable	739,426	530,061	411,858	336,337	284,050

(1) “Net Revenue” is net revenue after royalties.

(2) Including solution gas and other by-products.

(3) Including by-products, but excluding solution gas from oil wells.

($M)	After Future Income Tax Expenses and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed Producing	270,383	213,850	179,674	156,398	139,432
Developed Non-Producing	39,124	30,807	25,213	21,223	18,247
Undeveloped	93,827	67,924	50,465	38,106	29,007
Total Proved	403,334	312,581	255,352	215,727	186,686
Probable	198,286	119,368	80,635	58,775	45,133
Total Proved plus Probable	601,620	431,949	335,987	274,502	231,819

	Discounted at 10%/Year ($/BOE)
Proved	
Developed Producing	27.80
Developed Non-Producing	22.18
Undeveloped	21.74
Total Proved	25.41
Probable	19.69
Total Proved plus Probable	23.59

(1) "Net Revenue" is net revenue after royalties.

(2) Including solution gas and other by-products.

(3) Including by-products, but excluding solution gas from oil wells.

PRICING ASSUMPTIONS – FORECAST PRICES AND COSTS

Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2010 in the Sproule Report in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2010 are also reflected in the following table.

	Medium and Light Crude Oil			Natural Gas	NGLs			
Year	WTI Cushing Oklahoma 40° API (US$/BBL)	Edmonton Par Price 40° API ($/BBL)	Cromer Medium 29.3° API ($/BBL)	AECO Gas Price ($/MMBTU)	Pentanes Plus FOB Field Gate ($/BBL)	Butanes FOB Field Gate ($/BBL)	Inflation Rates (%/YR)	Exchange Rate ($US/$CDN)
2010 (Actual)	79.43	77.81	73.66	4.16	84.21	57.04	1.0	0.971
2011	88.40	93.08	85.63	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	86.34	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	85.02	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	84.18	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	85.45	6.69	97.24	63.69	1.5	0.932
2016	91.57	96.38	86.74	6.80	98.70	64.65	1.5	0.932
2017	92.94	97.84	88.05	6.91	100.18	65.62	1.5	0.932
2018	94.34	99.32	89.38	7.02	101.68	66.60	1.5	0.932
2019	95.75	100.81	90.73	7.14	103.21	67.60	1.5	0.932
2020	97.19	102.34	92.10	7.26	104.76	68.61	1.5	0.932

RECONCILIATION OF CHANGES IN RESERVES

The following table sets forth a reconciliation of Surge's gross reserves as at December 31, 2010, derived from the Sproule Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2009. The additional reserves associated with royalty interest reserves, representing 2,438 Mboe and 3,756 Mboe on a Proved and Proved plus Probable basis, respectively, are not included in the following tables.

	LIGHT AND MEDIUM CRUDE OIL (MBBLS)	HEAVY OIL (MBBLS)	NATURAL GAS LIQUIDS (MBBLS)	NATURAL GAS (MMCF)	BOE (MBOE)
Proved					
Balance at December 31, 2009	1,271.0	2,564.6	347.0	15,967.0	6,843.8
Extensions and improved recovery	1,201.5	615.0	269.5	7,109.0	3,270.9
Technical revisions	176.2	48.8	(3.1)	705.0	339.4
Discoveries	-	-	-	-	-
Acquisitions	2,243.0	-	306.3	15,635.0	5,155.1
Dispositions	-	-	(39.0)	(641.0)	(145.8)
Economic factors	-	-	-	-	-
Production	(372.4)	(273.1)	(37.5)	(2,527.0)	(1,104.2)
Balance at December 31, 2010	4,519.3	2,955.3	843.2	36,248.0	14,359.2

	LIGHT AND MEDIUM CRUDE OIL (MBBLS)	HEAVY OIL (MBBLS)	NATURAL GAS LIQUIDS (MBBLS)	NATURAL GAS (MMCF)	BOE (MBOE)
Probable					
Balance at December 31, 2009	481.4	997.4	164.2	8,502.0	3,060.1
Extensions and improved recovery	1,023.9	397.2	138.0	4,011.0	2,227.6
Technical revisions	(157.1)	(86.3)	(66.8)	(3,068.0)	(821.4)
Discoveries	-	-	-	-	-
Acquisitions	980.3	-	169.4	7,599.0	2,416.2
Dispositions	-	-	(7.6)	(125.0)	(28.5)
Economic factors	-	-	-	-	-
Production	-	-	-	-	-
Balance at December 31, 2010	2,328.5	1,308.3	397.2	16,919.0	6,854.0

	LIGHT AND MEDIUM CRUDE OIL (MBBLS)	HEAVY OIL (MBBLS)	NATURAL GAS LIQUIDS (MBBLS)	NATURAL GAS (MMCF)	BOE (MBOE)
Proved plus Probable					
Balance at December 31, 2009	1,752.4	3,562.0	511.2	24,470.0	9,903.9
Extensions and improved recovery	2,225.4	1,012.2	407.5	11,121.0	5,498.5
Technical revisions	19.1	(37.5)	(69.8)	(2,363.0)	(482.0)
Discoveries	-	-	-	-	-
Acquisitions	3,223.3	-	475.7	23,234.0	7,571.3
Dispositions	-	-	(46.6)	(766.0)	(174.2)
Economic factors	-	-	-	-	-
Production	(372.4)	(273.1)	(37.5)	(2,527.0)	(1,104.2)
Balance at December 31, 2010	6,847.8	4,263.6	1,240.5	53,169.0	21,213.3

FINDING AND DEVELOPMENT (F&D) AND FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS

CAPITAL COSTS ($MM)	FD&A	F&D
2010 capital expenditures (excl. non-cash items):	$230.8	$42.0
Change in FDC(4)		
Proved	$47.0	$34.8
Proved plus Probable	$57.3	$24.0
Total capital (excl. non-cash items) including change in FDC ($MM)(4)		
Proved	$277.8	$76.8
Proved plus Probable	$288.1	$66.0
FD&A and F&D costs without FDC ($/boe)	FD&A	F&D
Proved	$26.78	$9.61
Proved plus Probable	$18.59	$8.37
FD&A and F&D costs including FDC ($/boe)(4)		
Proved	$32.23	$17.59
Proved plus Probable	$23.21	$13.15

Surge's netback for 2010 was $27.65 per boe. Using this netback the following recycle ratios were calculated:

RECYCLE RATIO INCLUDING FDC(4)	FD&A	F&D
Proved	0.9	1.6
Proved plus Probable	1.2	2.1

(4) Calculated using the Corporation's undiscounted future development capital cost.

Surge produced 1.1 million boe of oil and natural gas in 2010 (3,026 boe per day) and added 12.4 million boe of Proved plus Probable reserves, resulting in a reserves replacement ratio of 11.2.

RESERVE REPLACEMENT	
Proved	7.8
Proved plus Probable	11.2

SURGE 2010 NET ASSET VALUE PER FULLY DILUTED SHARE INFORMATION

Using reserve value at December 31, 2010 and forecast pricing and costs:

($MM Except Share Amounts)

PROVED PLUS PROBABLE RESERVE VALUE (NET PRESENT VALUE DISCOUNTED 10 PERCENT BEFORE TAX)	
(incl. future capital)	$411.9
Undeveloped land (435,413 acres @ $100/acre)(5)	$43.5
Estimated net debt	($46.0)
Option proceeds	$27.3
Total net assets (basic)	409.4
Total net assets (fully diluted)	$436.7
Basic shares outstanding (MM)	56.1
Fully diluted shares outstanding (MM)	60.8
Estimated NAV per basic share	$7.30
Estimated NAV per fully diluted share	$7.18

(4) Calculated using the Corporation's undiscounted future development capital cost.

(5) Internal estimate equivalent to $100 per net corporate undeveloped acre.

MD&A

FINANCIAL AND OPERATING SUMMARY ($000s except per share amounts)

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Financial highlights						
Oil and NGL sales	**15,014**	9,999	50%	**47,685**	30,697	55%
Natural gas sales	**3,322**	2,934	13%	**10,029**	12,156	(17%)
Other revenue	**208**	-	nm	**213**	-	nm
Total oil, natural gas, and NGL revenue	**18,544**	12,933	43%	**57,927**	42,853	35%
Funds from operations(1)	**7,907**	5,320	49%	**25,688**	17,492	47%
Per share basic and diluted ($)	**0.15**	0.32	(53%)	**0.70**	1.05	(33%)
Net loss excluding non-recurring charges relating to the recapitalization(2)	**(4,147)**	(21)	nm	**(1,307)**	(2,112)	(38%)
Net earning (loss)	**(4,147)**	(21)	nm	**(10,326)**	(2,112)	389%
Per share basic and diluted ($)	**(0.08)**	-	nm	**(0.28)**	(0.13)	115%
Corporate & asset acquisitions (cash and share consideration)(3)	**66,239**	-	nm	**188,812**	-	nm
Capital expenditures	**26,465**	5,154	414%	**41,996**	17,888	135%
Net debt at end of period(4)	**46,240**	46,902	3%	**46,240**	46,902	3%
Operating highlights						
Production:						
Oil and NGL (bbls per day)	**2,308**	1,614	43%	**1,871**	1,477	27%
Natural gas (mcf per day)	**10,182**	6,887	48%	**6,930**	6,995	(1%)
Total (boe per day) (6:1)	**4,005**	2,762	45%	**3,026**	2,643	14%
Netback (excluding hedges) ($ per boe):						
Oil, natural gas and NGL sales	**50.33**	50.90	(1%)	**52.45**	44.42	18%
Royalties	**(6.43)**	(5.77)	11%	**(7.35)**	(5.23)	41%
Operating expenses	**(14.87)**	(15.60)	(5%)	**(15.25)**	(13.52)	13%
Transportation expenses	**(1.72)**	(1.84)	(7%)	**(2.20)**	(2.03)	8%
Operating netback	**27.31**	27.69	(1%)	**27.65**	23.64	17%
G&A expenses	**(5.96)**	(4.32)	38%	**(5.60)**	(4.03)	39%
Interest expense	**(0.80)**	(2.37)	(66%)	**(0.90)**	(2.11)	(57%)
Corporate netback	**20.55**	21.00	(2%)	**21.15**	17.50	21%
Common shares (000s)						
Common shares outstanding, end of period	**56,095**	17,836	215%	**56,095**	17,836	215%
Weighted average basic shares outstanding	**53,065**	16,667	218%	**36,468**	16,700	118%
Stock option dilution (treasury method)	**-**	(69)	nm	**-**	-	nm
Weighted average diluted shares outstanding	**53,065**	16,736	217%	**36,468**	16,700	118%

(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 Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other entities.

(2) Excluding the non-recurring recapitalization costs, as well as the increase in stock-based compensation that resulted from the recapitalization. Please see net income (loss) note.

(3) Please see capital expenditures note.

(4) The Corporation defines net debt as outstanding bank debt plus or minus cash-based working capital.

OVERVIEW AND HIGHLIGHTS

Surge is pleased with the transformation achieved since recapitalizing Zapata Energy Corporation on April 13, 2010. The Corporation is now well positioned in three exciting light oil resource plays and commenced drilling in these key light oil resource plays late in 2010. Upon the closing of the recently announced North Dakota acquisitions expected on May 12, 2011, Surge will have: a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP(1) of more than 460 million barrels and more than 460 gross (350 net) oil drilling locations.

A timeline of some of the major events in 2010 is as follows:

- March 25, 2010: Announced the recapitalization of Zapata Energy Corporation.
- April 13, 2010: Entered into a reorganization and investment agreement, completed a $17 million non-brokered private placement in conjunction with the recapitalization and named the new Board of Directors and management team.
- May 5, 2010: Completed a bought deal financing for total proceeds of $50 million.
- June 25, 2010: Re-named the Corporation Surge Energy Inc. and changed the stock ticker symbol to SGY.
- July 12, 2010: Completed the acquisition of Corinthian Energy Corporation for 16.0 million common shares and the assumption of approximately $15 million of net debt which added two high impact light oil resource plays, 125 gross (100 net) light oil horizontal drilling locations, and 80,000 acres of net undeveloped land and more than 160 million barrels of DPIIP.
- July 12, 2010: Acquired an additional 25 percent Unit Interest at Waskada in South West Manitoba.
- July 20, 2010: Increased bank line from $50 million to $80 million and completed the acquisition of Crystal Lake Resources Ltd. for 0.3 million common shares.
- October 20, 2010: Completed a subscription receipt bought deal financing for gross proceeds of $42 million.
- November 1, 2010: Completed the acquisition of a low decline light oil resource play asset with all season access at Valhalla South for $75 million, which added 24 gross (15.3 net) light oil horizontal drilling locations and more than 100 million barrels of DPIIP and increased the bank line from $80 million to $90 million.
- Subsequent to the year ended December 31, 2010, Surge increased its bank line from $90 million to $105 million and the Corporation forecasts that its bank line will increase to $120 million in May of 2011.
- Established a non-core dispositions package which has successfully resulted in approximately $6.5 million of proceeds for Surge to date.
- Executed preparation for 2011 drilling program targeting light oil, which is projected to increase operating netbacks to approximately $47.00(2) by the fourth quarter of 2011 and increase light/medium oil weighting to greater than 70 percent.
- Surge had greater than 245 gross (more than 220 net) oil drilling locations in inventory at December 31, 2010, currently has more than 350 gross (more than 265 net) oil drilling locations and forecasts having more than 460 gross (more than 350 net) oil drilling locations in inventory after the closing of the previously announced acquisitions in North Dakota expected for May 12, 2011.

(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 economically viable or technically feasible to produce any portion of this DPIIP except for those identified as proved or probable reserves. There is no certainty that it will be commercially viable to produce any portion of the resources.

(2) Based on April 18, 2011 forward strip: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346 for the fourth quarter.

ACHIEVEMENTS AND FORECAST:

- Increased production by 125 percent from approximately 2,000 boe per day shortly after the recapitalization in April 2010 to a 2010 exit production rate of more than 4,500 boe per day with a forecast to exit 2011 at 7,500 boe per day, with oil and NGL weighting increasing from 60 percent to more than 70 percent.
- Realized an average production rate of 4,005 boe per day in the fourth quarter 2010, a 45 percent increase as compared to 2009 production rate of 2,762 boe per day with a forecast to grow exit production by 67 percent to 7,500 boe/d in 2011.
- Realized an average production rate of 3,026 boe per day for the year ended December 31, 2010, a 14 percent increase as compared to the 2009 production rate of 2,643 boe per day; with a forecast to grow production by 98 percent to an average of 6,000 boe/d in 2011.
- More than 80 percent of Surge's revenue in 2010 resulted from oil and natural gas liquids production, with less than 20 percent derived from natural gas production.
- Increased Proved plus Probable reserves by 114 percent from 9.9 million boe at December 31 2009 to 21.2 million boe at December 31, 2010.
- Increased the NPV10 BT of Proved plus Probable reserves by 90 percent from $217 million as at December 31, 2009 to $412(3) million as at December 31, 2010.
- Achieved Proved plus Probable Finding and Development ("F&D") costs of $13.15 per boe, including a $24.0 million change in Future Development Capital ("FDC").
- Achieved an F&D recycle ratio for 2010 of 2.1 times.
- Attained a Proved plus Probable Reserve Life Index of 12.9 years based on the Corporation's estimated 2010 exit production rate of approximately 4,500 boe per day.
- Achieved a Proved plus Probable reserves replacement ratio of 11.2 based on the Corporation's estimated 2010 average production for the year of 3,026 boe per day.
- Achieved a 100 percent success rate drilling 10 gross (10 net) wells in the fourth quarter 2010; realized a gross success rate of 91 percent drilling by 22 gross (21.5 net) wells in 2010.
- Reduced operating expenses per boe by five percent and transportation expenses per boe by seven percent in the fourth quarter of 2010 as compared to the fourth quarter of 2009, with a forecast to reduce combined operating and transportation costs by 21 percent to $13.00 per boe in the fourth quarter of 2011.
- Increased Surge's operating netback by 17 percent for the year ended December 31, 2010 as compared to the year ended December 31, 2009 from $23.64 per boe to $27.65 per boe. Surge's fourth quarter 2011 netback is forecast to be approximately $47.00(2) per boe based on recent 2011 strip oil and gas prices and as a result of the Corporation's increasing light oil weighting and decreasing costs in 2011.
- Increased funds from operations by 49 percent to $8.0 million in the fourth quarter of 2010 from $5.3 million in the fourth quarter of 2009; Increased funds from operations by 47 percent to $25.7 million in 2010 from $17.5 million in 2009 with a forecast to grow funds from operations by 189 percent to $75(4) million in 2011.

(2) Based on April 18, 2011 forward strip: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346 for the fourth quarter.

(3) The estimated values disclosed do not represent fair market value.

(4) Based on April 18, 2011 forward strip: CDN $99.06 Edmonton Par (US$106.12 WTI) and CDN $3.90/mcf AECO using a CAD/USD of 1.0307.

NETBACK COMPARISON

		Q4 2010		Q3 2010	% CHANGE
Average production (boe per day)		**4,005**		3,138	28%
Revenue	**$**	**50.33**	$	49.41	2%
Royalties		**(6.43)**		(6.07)	6%
Operating costs		**(14.87)**		(14.98)	(1%)
Transportation costs		**(1.72)**		(1.86)	(8%)
Operating netback	**$**	**27.31**	$	26.50	3%

The Corporation continued to achieve reductions in both operating costs and transportation expenses on a per boe basis in the fourth quarter of 2010 as compared to the third quarter of 2010. Surge's operating netback increased by three percent from $26.50 in the third quarter of 2010 to $27.31 in the fourth quarter of 2010. The management team continues to focus on finding efficiencies within existing operations and expects operating netbacks to continue to grow through 2011. Surge exited 2010 with a low decline (approximately 15 percent) oil-weighted production base of more than 4,500 boe per day and maintains a significant undeveloped land base of more than 400,000 net acres. Surge maintained approximately $59 million of borrowing capacity at year-end on the Corporation's $105 million bank line, with $46 million of net debt at year-end (defined as outstanding bank debt plus or minus cash-based working capital).

OUTLOOK

Surge has built a low decline, oil-weighted production base and positioned itself in several high impact, emerging light oil resource plays. Upon the closing of the recently announced North Dakota acquisitions expected on May 12, 2011, Surge will have: a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP of more than 460 million barrels (gross) and more than 460 gross (350 net) oil drilling locations, comprised of 85 percent light oil, with the remainder of the inventory being medium gravity.

During 2010, since the recapitalization of Zapata on April 13, 2010 Surge has positioned itself in three high impact light oil resource plays at Valhalla South (Doig), Windfall (Bluesky) and South West Manitoba (Spearfish), adding more than 190 gross (175 net) light oil horizontal drilling locations, 80,000 acres of net undeveloped land and more than 245 million barrels (gross) of DPIIP.

Surge has had an excellent start to 2011 and continues to implement its business plan of targeting per share growth by positioning the Corporation in high impact oil resource plays with significant oil in place and applying its proven expertise and experience to build core areas. Surge continues to demonstrate this ability with the recent announcement of its expansion into North Dakota, where the Corporation significantly strengthened its position in the Spearfish light oil resource play by adding 205 gross (120 net) light oil horizontal drilling locations on 6,000 net acres of highly prospective lands. Management estimates DPIIP to be approximately 125 million barrels (gross) within these lands.

Complementary to Surge's high impact light oil resource plays at Valhalla South (Doig), Windfall (Bluesky) and South West Manitoba/North Dakota (Spearfish) are the low cost, low decline, high rate of return oil resource assets in South East Alberta that have considerable secondary recovery potential. The infill drilling and secondary recovery programs that have been implemented to date provide significant internally generated cash flow and enable Surge to execute its capital program in each of its core areas.

In 2011, Surge will continue to grow the Corporation organically through drilling, continued development of secondary recovery programs in South East Alberta and by evaluating plans for secondary recovery pilot programs on its new light oil resource plays. Additionally, the Corporation will continue to make accretive acquisitions that fit its business plan of positioning Surge in high impact, emerging crude oil resource plays. 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. Surge looks forward to applying for listing of its common shares on the Toronto Stock Exchange in the fourth quarter of 2011.

By the end of May 2011, Surge anticipates finalizing its syndicated bank facility and increasing its line of credit to $120 million. Surge's 2010 year end net debt was $46 million (defined as outstanding bank debt plus or minus cash-based working capital) representing 0.6 times forecast 2011 funds flow based on April 18, 2011 forward strip pricing and Surge forecasts 2011 year end net debt of $91 million representing 0.8 times forecast annualized fourth quarter 2011 funds flow based on April 18, 2011 forward strip pricing.

Surge forecasts a 2011 capital program of $120 million with guidance to achieve 2011 exit production of 7,500 boe per day (greater than 70 percent light/medium oil and NGLs), a 67 percent increase over 2010, with 2011 annual production of 6,000 boe per day (greater than 65 percent light/medium oil and NGLs), a 98 percent increase over 2010. Based this 2011 production guidance, Surge is forecasting an increase in funds from operations of approximately 189 percent as compared to 2010 to approximately $75 million in 2011 (based on April 18, 2011 forward strip pricing).

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"), formerly Zapata Energy Corporation, which includes its subsidiaries and partnership arrangements, is for the three months and years ended December 31, 2010 and 2009. 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, press releases and the Annual Information Form (AIF). These documents are available at www.sedar.com.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements.

More particularly, this MD&A contains statements concerning anticipated: (i) production weighting for 2011, (ii) exploration and development activities, (iii) changes to the Alberta royalty regime regulations in force, (iv) effect on Surge of anticipated changes to the Alberta royalty regime, (v) capital expenditures for 2011, (vi) sources of funding for future capital requirements, (vii) outcome and effect on Surge of outstanding legal proceedings and claims, (viii) amounts received or paid to settle financial instruments currently entered into upon maturity, and (ix) changes to accounting policies. 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 and the application of regulatory and royalty regimes.

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 this MD&A and in Surge's AIF 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.

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 Canadian generally accepted accounting principles (GAAP). 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 GAAP, 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:

	3 MONTHS ENDED DECEMBER 31,		YEARS ENDED DECEMBER 31,	
($000s)	2010	2009	2010	2009
Cash flow from operating activities (per GAAP)	**594**	5,732	**17,137**	16,341
Change in non-cash working capital	**7,313**	(412)	**3,142**	1,151
Non-recurring recapitalization costs	**-**	-	**5,409**	-
Funds from operations	**7,907**	5,320	**25,688**	17,492

Funds from operations per share is calculated using the weighted average basic and diluted shares used in calculating earnings per share. Operating and corporate netbacks are also presented. Operating netbacks represent Surge's revenue, excluding realized and unrealized gains or losses on commodity 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.

The term “net income (loss) before and after tax, excluding non-recurring charges relating to the recapitalization” used in this discussion is not a recognized measure under Canadian generally accepted accounting principles (GAAP). Management believes that in addition to net income, net income (loss) before and after tax, excluding non-recurring charges relating to the recapitalization is a useful supplemental measure, as it provides an indication of the results generated by the Corporation’s principal business activities before the consideration of non-recurring recapitalization costs. Investors are cautioned, however, that these measures should not be construed as alternatives to net income determined in accordance with GAAP, as an indication of Surge’s performance.

Excluding the non-recurring recapitalization costs, as well as the increase in stock-based compensation that resulted from the recapitalization, the Corporation’s approximate net loss would have been $4.1 million for the three months ended December 31, 2010 and $1.3 million for the year ended December 31, 2010.

	3 MONTHS ENDED DECEMBER 31,		YEARS ENDED DECEMBER 31,	
($000s)	2010	2009	2010	2009
Loss before taxes (per GAAP)	**(3,899)**	(506)	**(11,147)**	(3,716)
Add back:				
Recapitalization costs	**-**	-	**5,409**	-
Stock-based compensation expense relating to the recapitalization	**-**	-	**3,610**	-
Net income (loss) before tax excluding non-recurring charges relating to the recapitalization	**(3,899)**	(506)	**(2,128)**	(3,716)
Future income tax (reduction)	**248**	(485)	**(821)**	(1,604)
Net income (loss) excluding non-recurring charges relating to the recapitalization	**(4,147)**	(21)	**(1,307)**	(2,112)

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 April 27, 2011.

OPERATIONS

DRILLING

	DRILLING		SUCCESS RATE	WORKING
	GROSS	NET	(%) GROSS	INTEREST (%)
Q1 2010	1	0.5	100%	50%
Q2 2010	6	6	83%	100%
Q3 2010	5	5	80%	100%
Q4 2010	10	10	100%	100%
Total	**22**	**21.5**	**91%**	**98%**

Surge achieved a 100 percent success rate in the fourth quarter of 2010, drilling 10 gross (10 net) wells, resulting in 10 gross (10 net) oil wells. During 2010, Surge achieved an 91 percent success rate drilling 22 gross (21.5 net) wells.

PRODUCTION

	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Oil & NGL (bbls per day)	**2,308**	1,841	1,621	1,707	1,614	1,428	1,374	1,492
Natural gas (mcf per day)	**10,182**	7,783	3,823	5,874	6,887	6,294	7,586	7,223
Total (boe per day)(6:1)	**4,005**	3,138	2,258	2,686	2,762	2,477	2,638	2,696
% Oil & NGL	**58%**	59%	72%	64%	58%	58%	52%	55%

Surge achieved production of 4,005 boe per day in the fourth quarter of 2010, a 45 percent increase from the fourth quarter of 2009 production rate of 2,762 boe per day. Average production during 2010 was 3,026 boe per day as compared to 2,643 boe per day during 2009. The increase in the quarterly and year to date production volumes compared to the 2009 rates was primarily due to increased production from acquisitions and new drills and partially offset by approximately 3,000 mcf a day of gas that was shut in over the course of 2010.

Surge realized a 58 percent oil and natural gas liquids production weighting in the fourth quarter of 2010. The Corporation realized average oil and natural gas liquids production of 2,308 bbls per day for the fourth quarter of 2010.

OIL, NATURAL GAS AND NGL, COMMODITY CONTRACTS AND OTHER REVENUES

A one percent decrease in average revenue per boe, combined with a 45 percent increase in production, resulted in revenues of $18.5 million in the fourth quarter of 2010, up 43 percent from $12.9 million in the fourth quarter of 2009. During 2010, an 18 percent increase in average revenue per boe, coupled with a 14 percent increase in volume, resulted in revenues of $57.9 million, up 35 percent from $42.9 million during 2009.

Surge had certain oil and gas commodity contracts in place as of December 31, 2010. The Corporation recognized an unrealized loss of $2.6 million and a realized gain of $0.7 million on its commodity contracts in the fourth quarter of 2010. This compares to an unrealized loss of $1.1 million and a realized gain of $0.1 million on its commodity contracts in the fourth quarter of 2009.

Realized commodity contract gains resulted in an increase of $1.92 per boe to the average revenue, including commodity contracts, for the fourth quarter of 2010. Realized commodity contract gains resulted in an increase of $0.54 per boe to average revenue, including commodity contracts, for the fourth quarter of 2009.

The Corporation recognized an unrealized loss of $2.3 million and a realized gain of $2.8 million on its commodity contracts during 2010. This compares to an unrealized loss of $1.2 million and a realized gain of $0.9 million on its commodity contracts during 2009.

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

In the fourth quarter of 2010, Surge realized average revenue of $50.33 per boe, before realized commodity contract gains, a decrease of one percent from the $50.90 per boe recorded in the fourth quarter of 2009. During 2010, Surge realized average revenue of $52.45 per boe, before realized commodity contract gains, an increase of 18 percent from the $44.42 per boe recorded during 2009.

Surge realized an average of $70.70 per bbl of oil and natural gas liquids in the fourth quarter of 2010, an increase of five percent per barrel from the $67.35 per bbl realized in the fourth quarter of 2009. This compares to an average Edmonton Light Sweet price of $80.33 per bbl in the fourth quarter of 2010, which increased five percent per barrel from the $76.56 per bbl in the fourth quarter of 2009. The increase in oil and natural gas liquids prices is consistent with the increase in benchmark prices.

Surge realized an average of $69.83 per bbl of oil and natural gas liquids during 2010, an increase of 23 percent per barrel from the $56.93 per bbl realized during 2009. This compares to an average Edmonton Light Sweet price of $77.48 per bbl during 2010, which increased 17 percent per barrel from the $65.98 per bbl during 2009. The increase in oil and natural gas liquids prices is relatively consistent with the increase in benchmark prices as well as an improvement in differentials due to increased light oil production.

The Corporation realized an average natural gas price of $3.55 per mcf in the fourth quarter of 2010, a 23 percent decrease from the $4.63 per mcf averaged in the fourth quarter of 2009. This compares to an average Alberta Plant Gate reference price of $3.43 per mcf in the fourth quarter of 2010 and $4.26 per mcf in the fourth quarter of 2009 reflecting a 19 percent decrease. The decrease in natural gas prices is relatively consistent with the decrease in benchmark prices.

The Corporation realized an average natural gas price of $3.96 per mcf during 2010, a 17 percent decrease from the $4.76 per mcf averaged during 2009. This compares to an average Alberta Plant Gate reference price of $3.79 per mcf during 2010 and $3.74 per mcf during 2009 reflecting a one percent increase. The difference in the average realized natural gas price is due to physical natural gas hedge gains included in the year ended December 31, 2009 natural gas revenue, amounting to approximately $0.80 per mcf.

More than 80 percent of Surge's revenue resulted from oil and natural gas liquids production, with less than 20 percent derived from natural gas production.

Realized commodity contract gains resulted in an increase of $2.53 per boe to the average revenue including commodity contracts during 2010. Realized commodity contract gains resulted in an increase of $0.90 per boe to average revenue including commodity contracts during 2009.

REVENUE AND REALIZED PRICES

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Oil and NGL ($000s)	**15,014**	9,999	50%	**47,685**	30,697	55%
Natural gas ($000s)	**3,322**	2,934	13%	**10,029**	12,156	(17%)
Processing and other ($000s)	**208**	-	nm	**213**	-	nm
Total oil, natural gas and NGL revenue ($000s)	**18,544**	12,933	43%	**57,927**	42,853	35%
Oil and NGL ($ per bbl)	**70.70**	67.35	5%	**69.83**	56.93	23%
Natural gas ($ per mcf)	**3.55**	4.63	(23%)	**3.96**	4.76	(17%)
Total oil, natural gas and NGL revenue ($ per boe)	**50.33**	50.90	(1%)	**52.45**	44.42	18%
Unrealized gain loss) on commodity contracts ($ per boe)	**(7.19)**	(4.39)	64%	**(2.13)**	(1.27)	68%
Realized gain(loss) on commodity contracts ($ per boe)	**1.92**	0.54	256%	**2.53**	0.90	181%
Total oil, natural gas, and NGL revenue after commodity contracts ($ per boe)	**45.06**	47.05	(4%)	**52.85**	44.05	20%
Reference Prices						
Edmonton par - light oil ($ per bbl)	**80.33**	76.56	5%	**77.48**	65.98	17%
Alberta reference price ($ per mcf)	**3.43**	4.26	(19%)	**3.79**	3.74	1%

ROYALTIES

Surge realized royalty expense of $2.4 million or 13 percent of revenue in the fourth quarter of 2010, compared to $1.5 million or 11 percent of revenue in the fourth quarter of 2009. During 2010, Surge realized royalty expense of $8.1 million or 14 percent of revenue, compared to $5.0 million or 12 percent of revenue during 2009.

The increase in royalties as a percentage of revenue during 2010 compared to the same periods in 2009 is primarily due to $0.5 million of prior period royalty adjustments recorded in the second quarter of 2010. Excluding these prior period adjustments, royalties would have been approximately 13 percent of revenue.

On January 1, 2009 the Alberta government's Alberta Royalty Framework (ARF) took effect. Under the ARF, royalty rates on conventional and non-conventional oil and natural gas production in Alberta may increase to a maximum of 50 percent. The sliding scale royalty calculations are based on a broader range of commodity prices and production rates.

In response to the drop in commodity prices experienced during the second half of 2008, on November 19, 2008, the Government of Alberta announced the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil wells (deeper than 1,000 metres and no deeper than 3,500 metres) will be given a one-time option, on a producing zone per well basis, to adopt either the new transitional royalty rates or those outlined in the ARF. In order to qualify for this program, wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the ARF.

On March 3, 2009, an incentive program designed to encourage the execution of new drilling projects in Alberta was announced in response to the global economic crisis and slowdown in drilling activity throughout the province of Alberta. The incentive program provides for a drilling royalty credit for new conventional oil and natural gas wells that initiate drilling on or after April 1, 2009 and that complete drilling by March 31, 2010. The incentive program also provides a reduced royalty rate on new wells for the first year of production or up to an established total production volume of 50,000 boe (boe cap is calculated at 10:1).

In 2010, the Government of Alberta announced that this program will be permanently implemented. This incentive program is expected to positively impact the Corporation.

In April 2010, the Government of Alberta announced an additional royalty incentive program relating to horizontal oil well drilling projects. Horizontal oil wells drilled on or after May 1, 2010 qualify for the Horizontal Oil New Well Royalty Rate program. This incentive program provides a reduced royalty rate on new horizontal oil wells for the first 18 to 48 months of production, based on drilling depth, up to an established total production volume of 50,000 to 100,000 boe (boe cap is calculated at 10:1).

During 2010, Surge recorded $2.6 million of drilling royalty credits as a reduction to capital costs.

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

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Total ($000s)	**2,371**	1,466	62%	**8,122**	5,046	61%
% of Revenue	**13%**	11%	2%	**14%**	12%	2%
$ per boe	**6.43**	5.77	11%	**7.35**	5.23	41%

OPERATING EXPENSE

Operating expense per boe decreased five percent in the fourth quarter of 2010 to $14.87 per boe as compared to $15.60 per boe in the same period of 2009. Total operating expenses in the fourth quarter of 2010 were $5.5 million, up 38 percent from $4.0 million in the fourth quarter of 2009. During 2010, operating expense per boe increased 13 percent during 2010 to $15.25 per boe as compared to $13.52 per boe in the same period of 2009. Total operating expenses were $16.8 million, up 29 percent from $13.0 million during 2009.

The increase in operating expenses per boe in 2010 compared to the same periods in 2009 was mainly due to increased workover and maintenance expenditures relating to optimization projects. This increase was also attributable to increased government and regulatory costs, coupled with higher operating costs per boe on the acquired Corinthian assets.

Operating expenses per boe fell from $14.98 per boe in the third quarter of 2010 to $14.87 per boe in the fourth quarter of 2010, a less than one percent reduction. The management team continues to focus on finding efficiencies within existing operations and expects combined operating and transportation expenses per boe to continue decline into 2011.

OPERATING EXPENSES

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Total ($000s)	**5,481**	3,962	38%	**16,841**	13,042	29%
$ per boe	**14.87**	15.60	(5%)	**15.25**	13.52	13%

TRANSPORTATION EXPENSES

Transportation expenses in the fourth quarter of 2010 were $0.6 million or $1.72 per boe as compared to $0.5 million or $1.84 per boe recorded in the same period of 2009. The seven percent decrease in transportation costs per boe in the fourth quarter of 2010 compared to the same period in 2009 was primarily the result of a pipeline being constructed, connecting oil production from the Silver Battery. The pipeline tie in was completed during August of 2010. During 2010, transportation expenses totalled $2.4 million, a 24 percent increase over 2009 expense of $2.0 million. The eight percent increase in transportation costs per boe during 2010 compared to the same period in 2009 was primarily due to increased tariffs related to a three year transportation agreement recorded in the first quarter of 2010.

The management team continues to focus on finding efficiencies within existing operations and expects combined operating and transportation expenses per boe to continue decline.

TRANSPORTATION EXPENSES

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Total ($000s)	**634**	468	35%	**2,426**	1,961	24%
% of Revenue	**3%**	4%	(1%)	**4%**	5%	(1%)
$ per boe	**1.72**	1.84	(7%)	**2.20**	2.03	8%

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

Net G&A expenses for the fourth quarter of 2010 increased 38 percent to $5.96 per boe as compared to $4.32 per boe in the fourth quarter of 2009. Total G&A expenses for the fourth quarter of 2010, net of recoveries and capitalized amounts of $1.7 million, was $2.2 million, compared to $1.1 million in the fourth quarter of 2009, after recoveries and capitalized amounts of $0.06 million.

Net G&A expenses during 2010 increased to $5.60 per boe as compared to $4.03 per boe for the same period of 2009. Total G&A expenses during 2010, net of recoveries and capitalized amounts of $3.1 million, was $6.2 million, compared to $3.9 million in the same period of 2009, after recoveries and capitalized amounts of $0.3 million. The increase in net G&A expenses per boe in the fourth quarter and for the year is due primarily to additional rent on newly acquired office space, increased consulting and legal expenditures and increased staffing levels in 2010, in order to position the Corporation for future growth.

The increase in recoveries was a result of the management group capitalizing more administrative costs directly attributable to capital activities, due to an increased focus on these types of activities.

The management team expects G&A expenses per boe to decline throughout 2011.

G&A EXPENSES

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Total ($000s)	**3,878**	1,155	236%	**9,281**	4,209	121%
Recoveries and capitalized amounts	**(1,682)**	(57)	2,851%	**(3,096)**	(323)	859%
Net G&A expenses	**2,196**	1,098	100%	**6,185**	3,886	59%
Net G&A expenses per boe	**5.96**	4.32	38%	**5.60**	4.03	39%

RECAPITALIZATION COSTS

On April 13, 2010, the Corporation was recapitalized by a new management group and Board of Directors. During the course of the recapitalization, certain non-recurring recapitalization costs were incurred. These costs do not reflect the ongoing cost of business incurred by Surge and are comprised primarily of legal fees, financial adviser fees, severance and transaction due diligence costs.

RECAPITALIZATION COSTS

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Recapitalization costs ($000s)	**-**	-	-	**5,409**	-	nm

INTEREST EXPENSE

Surge incurred interest expense of $0.3 million or $0.80 per boe in the fourth quarter of 2010 as compared to $0.6 million or $2.37 per boe in the fourth quarter of 2009, a decrease of 66 percent per boe. During 2010, the Corporation incurred interest expense of $1.0 million or $0.90 per boe as compared to $2.0 million or $2.11 per boe during 2009, a decrease of 57 percent. The decrease is due to the repayment of Surge's outstanding debt during the second quarter of 2010 and the reduced outstanding balance throughout the remainder of 2010.

INTEREST EXPENSE

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Interest expense ($000s)	**295**	601	(51%)	**998**	2,036	(51%)
$ per boe	**0.80**	2.37	(66%)	**0.90**	2.11	(57%)

NETBACKS

During 2010, the operating netback per boe (defined as revenue excluding realized and unrealized gains or losses on commodity contracts per boe less royalties, operating and transportation expenses on a per boe basis) of the Corporation was $27.65 per boe, a 17 percent increase over the $23.64 per boe recorded during 2009. The increase in operating netback was largely due to an 18 percent increase in revenue per boe, partially offset by a 41 percent increase in royalty expenses per boe, a 13 percent increase in operating costs per boe and an eight percent increase in transportation expenses per boe during 2010 as compared to the same period in 2009.

Surge's operating netback per boe was $27.31 in the fourth quarter of 2010, a one percent decrease from $27.69 recorded in the fourth quarter of 2009. The decrease in operating netback was largely due to an 11 percent increase in royalty expenses per boe partially offset by a five percent decrease in operating costs per boe and a seven percent decrease in transportation expense per boe in the fourth quarter of 2010, compared to the same period in 2009.

During 2010, the corporate netback per boe (defined as operating netback per boe less G&A and interest expense per boe) of the Corporation was $21.15 per boe, a 21 percent increase over the $17.50 per boe recorded during 2009. The increase in corporate netback was impacted by the increase in G&A expense per boe in 2010 and offset by a decrease in interest expense per boe, as compared to the same period in 2009.

Surge's corporate netback per boe was $20.55 in the fourth quarter of 2010, a two percent decrease as compared to $21.00 in the fourth quarter of 2009. The decrease in corporate netback was impacted by the increase in G&A expense per boe in 2010 and offset by a decrease in interest expense per boe, as compared to the same period in 2009.

The management team continues to focus on finding efficiencies within existing operations and expects both operating and corporate netbacks to continue to grow throughout 2011.

CORPORATE AVERAGE NETBACKS

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
($ PER BOE, EXCEPT PRODUCTION)	2010	2009	% CHANGE	2010	2009	% CHANGE
Average production (boe per day)	**4,005**	2,762	45%	**3,026**	2,643	14%
Revenue	**50.33**	50.90	(1%)	**52.45**	44.42	18%
Royalties	**(6.43)**	(5.77)	11%	**(7.35)**	(5.23)	41%
Operating costs	**(14.87)**	(15.60)	(5%)	**(15.25)**	(13.52)	13%
Transportation costs	**(1.72)**	(1.84)	(7%)	**(2.20)**	(2.03)	8%
Operating netback	**27.31**	27.69	(1%)	**27.65**	23.64	17%
G&A expense	**(5.96)**	(4.32)	38%	**(5.60)**	(4.03)	39%
Interest expense	**(0.80)**	(2.37)	(66%)	**(0.90)**	(2.11)	(57%)
Corporate netback	**20.55**	21.00	(2%)	**21.15**	17.50	21%

FUNDS FROM OPERATIONS AND CASH FLOW FROM OPERATIONS

For the fourth quarter of 2010 funds from operations increased by 49 percent to $7.9 million compared to $5.3 million in the fourth quarter of 2009. On a per share basis, funds from operations decreased by 53 percent to $0.15 per basic share in the fourth quarter 2010 from $0.32 per basic share in the same period of 2009 due to equity issuances in the past year. Funds from operations increased by three percent on a per boe basis to $21.46 in the fourth quarter of 2010 from $20.94 in the fourth quarter of 2009.

During the past year, funds from operations increased by 47 percent to $25.7 million compared to $17.5 million during 2009. On a per share basis, funds from operations decreased by 33 percent to $0.70 per basic share during 2010 from $1.05 per basic share in the same period of 2009 due to equity issuances. Funds from operations increased by 28 percent on a per boe basis to $23.26 during 2010 from $18.13 during 2009.

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 fourth quarter of 2010 was $0.6 million as compared to $5.7 million in the fourth quarter of 2009. Included in cash flow from operations is a decrease in non-cash working capital of $7.4 million for the fourth quarter of 2010 and an increase of $0.4 million for the same period of 2009. Cash flow from operations during the past year was $17.1 million as compared to $16.3 million during 2009. Included in cash flow from operations is a decrease in non-cash working capital of $3.1 million during the past year, as well as a decrease due to recapitalization costs of $5.4 million, and a decrease of $1.2 million for the same period of 2009.

FUNDS FROM OPERATIONS

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Funds from operations ($000s)	**7,907**	5,320	49%	**25,688**	17,492	47%
Per share - basic	**0.15**	0.32	(53%)	**0.70**	1.05	(33%)
Per share - diluted	**0.15**	0.32	(53%)	**0.70**	1.05	(33%)
Per boe	**21.46**	20.94	3%	**23.26**	18.13	28%
Cash flow from operations ($000s)	**594**	5,732	(90%)	**17,137**	16,341	5%

STOCK-BASED COMPENSATION

Surge recorded stock-based compensation expense of $0.7 million in the fourth quarter of 2010 compared to $0.2 million for the same period of 2009, calculated using the Black-Scholes option-pricing model. During 2010, Surge recorded stock-based compensation expense of $5.4 million compared to $0.4 million for the same period of 2009.

During 2010, 2,636,000 options were issued at a weighted average exercise price of $6.38 per option and 295,000 options were forfeited at a weighted average price of $6.61 per option. In addition, as a result of the recapitalization transaction, all options held on April 13, 2010 vested in full and the remaining stock-based compensation on these options was recognized in the second quarter of 2010.

Included in stock-based compensation expense during 2010 is $3.6 million of stock based compensation expense related to the fair value of flow-through share premiums and performance warrants issued on April 13, 2010 as part of the recapitalization transaction. This amount was recorded in the second quarter of 2010.

The following assumptions were used to calculate stock-based compensation during 2010: zero dividend yield; expected volatility of 69 percent; risk free rate of two percent; and expected life of five years.

STOCK-BASED COMPENSATION EXPENSE

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Stock-based compensation expense ($000s)	**680**	211	222%	**5,351**	381	nm
Per boe	**1.85**	0.83	123%	**4.85**	0.39	nm

DEPLETION, DEPRECIATION AND ACCRETION (DD&A)

Depletion and depreciation are calculated based upon capital expenditures, production rates and reserves. Surge uses the asset retirement obligation method to record the present value of estimated clean-up and restoration costs for all of its facilities, including well sites and pipelines. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Excluded from the Corporation's depletion and depreciation calculation are costs associated with salvage values, unproven properties and seismic of $107.1 million. Future development costs for proved reserves of $63.8 million have been included in the depletion calculation.

Surge recorded $8.5 million or $22.94 per boe in DD&A expense in the fourth quarter of 2010, a 25 percent increase as compared to $18.32 per boe in DD&A expense in the fourth quarter of 2009.

During 2010, $23.7 million or $21.44 per boe in DD&A expense were recorded, a nine percent increase as compared to $19.72 per boe in DD&A expense during 2009.

The DD&A calculation is based on production volumes of 368,460 boe for the quarter and 1,104,490 boe for the year ended December 31, 2010. This increase in the DD&A rate per boe is due to the corporate acquisitions completed during the three months and year ended December 31, 2010.

DEPLETION, DEPRECIATION AND ACCRETION (DD&A) EXPENSE

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
(DD&A) ($000s)	**8,454**	4,654	82%	**23,681**	19,022	24%
Per boe	**22.94**	18.32	25%	**21.44**	19.72	9%

INCOME AND OTHER TAXES

Surge recognized a combined net future tax liability of approximately $34.6 million as at December 31, 2010, an increase of $16.9 million from the year-end 2009 future tax liability of $17.6 million. The future tax liability increased by $0.7 million related to the $2.6 million of flow-through shares issued in 2009 and renounced in 2010. The future tax liability also increased by $17.5 million related to Corinthian acquisition and decreased by $0.1 million due to the Crystal Lake acquisition. The future tax liability also decreased by the future tax reduction of $0.8 million for the year ended December 31, 2010.

As at December 31, 2010, the Corporation had incurred the entire $2.6 million towards this flow-through share obligation and has satisfied the terms of this flow-through share offering.

The provision for income taxes differs from the amount obtained by applying the combined federal and provincial income tax rate for 2010, which was 28 percent and is calculated on earnings before income taxes. The difference is mainly due to future tax rate differences.

TAX EXPENSES (REDUCTION)

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Tax expenses (reduction) ($000s)	**248**	(485)	(151%)	**(821)**	(1,604)	(49%)
Per boe	**0.67**	1.91	(65%)	**(0.74)**	(1.66)	(55%)

NET INCOME (LOSS)

The Corporation recorded net losses for the three months ended December 31, 2010 of $4.1 million or $0.08 per basic share, a decrease of 100 percent from the $0.00 per basic share recorded for the comparable three months of 2009. During 2010, the Corporation recorded net losses of $10.3 million or $0.28 per basic share, a decrease of 115 percent from the $0.13 per basic share recorded during 2009. The non-recurring recapitalization costs, combined with the increased stock-based compensation that resulted from the recapitalization and prior period royalty adjustments recorded in the second quarter of 2010, were large contributors to the net loss.

NET INCOME (LOSS)

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
	2010	2009	% CHANGE	2010	2009	% CHANGE
Total ($000s)	**(4,147)**	(21)	nm	**(10,326)**	(2,112)	389%
Per share - basic	**(0.08)**	-	nm	**(0.28)**	(0.13)	115%
Per share - diluted	**(0.08)**	-	nm	**(0.28)**	(0.13)	115%

NET INCOME (LOSS) EXCLUDING NON-RECURRING CHARGES RELATING TO THE RECAPITALIZATION

	3 MONTHS ENDED DECEMBER 31,		YEARS ENDED DECEMBER 31,	
($000S)	2010	2009	2010	2009
Net loss (per GAAP)	**(4,147)**	(21)	**(10,326)**	(2,112)
Add back:				
Recapitalization costs	**-**	-	**5,409**	-
Stock-based compensation expense relating to the recapitalization	**-**	-	**3,610**	-
Net income (loss) excluding non-recurring charges relating to the recapitalization	**(4,147)**	(21)	**(1,307)**	(2,112)

CAPITAL EXPENDITURES

Cash-based capital expenditures, net of any applicable Alberta drilling royalty credits, for the fourth quarter of 2010 were $92.7 million, an $87.6 million increase from the $5.2 million spent in the fourth quarter of 2009.

During 2010, Surge invested $31.5 million ($28.9 million net of $2.6 million in Alberta drilling royalty credits) to drill 22 gross (21.5 net) wells, $5.9 million on seismic and land acquisitions, $4.9 million on facilities and equipment, $76.8 million on property acquisitions ($75.3 million net of $1.4 million in disposition), $113.5 million on corporate acquisitions and $2.4 million on other capital items.

Non-cash corporate and property acquisition costs consist primarily of future income taxes and asset retirement obligations.

CAPITAL EXPENDITURE SUMMARY

	3 MONTHS ENDED DECEMBER 31,			YEARS ENDED DECEMBER 31,		
($000s)	2010	2009	% CHANGE	2010	2009	% CHANGE
Land and seimic	**1,441**	585	146%	**5,877**	2,382	147%
Drilling and intangibles	**22,204**	3,202	593%	**31,495**	11,042	185%
Alberta drilling royalty credits	**(1,388)**	(1,193)	16%	**(2,615)**	(1,543)	69%
Facilities and equipment	**3,116**	2,558	22%	**4,882**	5,812	(15%)
Other	**1,092**	1	100%	**2,357**	20	nm
	26,465	5,154	414%	**41,996**	17,713	137%
Corporate acquisitions	**-**	-	- %	**113,469**	-	100%
Property acquisitions	**67,670**	-	100%	**76,774**	-	100%
Property dispositions	**(1,431)**	-	100%	**(1,431)**	-	100%
Total cash and share-based acquisitions / dispositions	**66,239**	-	nm	**188,812**	-	nm
Total cash and share-based capital	**92,704**	5,154	nm	**230,808**	17,713	nm
Non-cash corporate acquisition costs	**-**	-	- %	**21,318**	-	100%
Non-cash property acquisition costs	**1,228**	-	100%	**1,228**	-	100%
Non-cash ARO Asset Additions	**109**	-	100%	**286**	175	63%
Capitalized SBC including future taxes	**794**	-	100%	**4,007**	-	100%
Total non-cash-based capital	**2,131**	-	100%	**26,839**	175	nm
Total capital additions	**94,835**	5,154	nm	**257,647**	17,888	nm

QUARTERLY AND ANNUAL FINANCIAL INFORMATION

	YEAR END 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010	YEAR END 2009	Q4 2009	Q3 2009	Q2 2009	Q1 2009	YEAR END 2008
Oil, natural gas & NGL sales	**57,927**	**18,544**	14,264	11,141	13,978	42,853	12,932	10,788	9,829	9,304	71,160
Unrealized gain (loss) on financial derivatives)	**(2,349)**	**(2,648)**	(1,110)	23	1,386	(1,222)	(1,116)	1,026	(22)	(1,110)	1,852
Provision for bad debt	**506**	**391**	-	-	115	840	-	-	840	-	3,053
Net earnings (loss)	**(10,326)**	**(4,147)**	(832)	(7,515)	2,168	(2,112)	(21)	844	(1,294)	(1,641)	7,698
Net earnings (loss) per share ($)											
Basic	**(0.28)**	**(0.08)**	(0.02)	(0.27)	0.12	(0.13)	-	0.05	(0.08)	(0.10)	0.45
Diluted	**(0.28)**	**(0.08)**	(0.02)	(0.27)	0.11	(0.13)	-	0.05	(0.08)	(0.10)	0.45
Total assets	**377,577**	**-**	-	-	-	132,360	-	-	-	-	135,410
Total long-term financial liabilities	**30,000**	**-**	-	-	-	41,650	-	-	-	-	39,650
Average daily sales											
Oil & NGL (bbls/d)	**1,871**	**2,308**	1,841	1,621	1,707	1,477	1,614	1,428	1,374	1,492	1,365
Natural gas (mcf/d)	**6,930**	**10,182**	7,783	3,823	5,874	6,995	6,887	6,295	7,586	7,223	9,056
Barrels of oil equivalent (boe per day) (6:1)	**3,026**	**4,005**	3,138	2,258	2,686	2,643	2,762	2,478	2,638	2,695	2,875
Average sales price											
Natural gas ($/mcf)	**3.96**	**3.55**	3.71	3.74	5.20	4.85	4.63	4.28	3.59	5.41	8.38
Oil & NGL ($/bbl)	**69.83**	**70.70**	69.33	66.57	72.35	58.84	69.52	62.39	58.48	42.18	82.77
Barrels of oil equivalent ($/boe)	**52.45**	**50.33**	49.41	54.22	57.83	45.32	51.44	47.34	39.88	37.82	65.96

SHARE CAPITAL AND OPTION ACTIVITY

	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Weighted Common Shares	**53,065,155**	30,874,642	27,589,374	18,576,487	16,669,721	16,666,811	16,668,503	16,695,117
Stock option dilution (treasury method)(1)	-	-	-	457,033	-	69,353	-	-
Weighted average dilution shares oustanding(1)	**53,065,155**	30,874,642	27,589,374	19,033,520	16,669,721	16,736,164	16,668,503	16,695,117

(1) In computing the net loss per diluted share, nil shares were added to the weighted average number of shares outstanding because they were anti-dilutive.

On January 19, 2010, the Corporation issued 848,600 units at a price of $3.00 per unit, with each unit consisting of one common share and one-half of a common share purchase warrant (with each whole warrant exercisable into one common share at a price of $4.00 per share until December 23, 2010), for total gross proceeds of $2,545,800. Certain former officers and directors purchased 20,000 units for total gross proceeds of $60,000.

On January 29, 2010, the Corporation issued 78,333 units at a price of $3.00 per unit, with each unit consisting of one common share and one-half of a common share purchase warrant (with each whole warrant exercisable into one common share at a price of $4.00 per share until December 23, 2010), for total gross proceeds of $235,000.

On April 13, 2010, pursuant to a private placement, the new management group, together with certain additional subscribers identified by the new management group, subscribed for 1,394,317 common units of the Corporation at a price of $4.40 per common unit, 1,787,500 common shares of the Corporation at a price of $4.40 per common share and 681,819 flow-through units at a price of $4.40 per flow-through unit, for total proceeds to the Corporation of approximately $17,000,000. Each common unit is comprised of one common share and one common share performance warrant, entitling the holder to purchase one common share at a price of $5.17 for a period of five years. Each flow-through unit is comprised of one common share issued on a flow-through basis pursuant to the Income Tax Act of Canada and one common share performance warrant, also entitling the holder to purchase one common share at a price of $5.17 for a period of five years. The common and flow-through shares issued as part of the common and flow-through units were ascribed a value of $3.30 per share or $6,851,000 due to the escrow restrictions described below. For further details on the vesting conditions and valuation of the common share performance warrants, please refer to note 8(d). The Corporation also recorded $331,000 of stock-based compensation on the flow-through units.

All of the units issued were acquired by contractors, employees, officers or directors of the Corporation ("deemed service providers"). For deemed service providers, units acquired through the private placement are held under an escrow agreement in which one-third of the units are to be released equally every six months following the date of issuance. No securities will be released from escrow after the date the deemed service provider ceases to be a service provider, unless directed by a resolution of the Board of Directors. Upon the deemed service provider ceasing to be a service provider, Surge will repurchase for cancellation or provide for a transfer to another deemed service provider all of the securities of the deemed service provider then held in escrow at a price equal to the lessor of $4.40 per unit and the market price of the common shares of Surge on the last day of trading immediately prior to the deemed service provider ceasing to be a service provider.

On May 5, 2010, the Corporation issued 6,945,000 common shares at a price of $7.20 per share for gross proceeds of $50,004,000, pursuant to a short form prospectus.

On July 9, 2010, the Corporation issued 16,025,529 common shares at an ascribed price of $5.90 per share in connection with the acquisition of Corinthian Energy Corp.

On July 19, 2010, the Corporation issued 288,639 common shares at an ascribed price of $5.90 per share in connection with the acquisition Crystal Lake Resources Ltd.

On November 1, 2010, the Corporation issued 8,001,000 common shares at a price of $5.25 per share for gross proceeds of $42.0 million.

During 2010, 672,199 warrants were exercised. As a result, the Corporation issued 672,199 common shares at a price of $4.00 for gross proceeds of $2.7 million.

During 2010, two share purchase loans aggregating $360,000 due from two former officers of the Corporation were repaid. The loans bore interest at a rate of 4.75 percent and were due on June 30, 2010. The entire amount of the principal and interest outstanding has been repaid and the related common shares totaling 160,000 were issued. The 160,000 shares attributable to the share purchase loans had been included in stock options.

On April 26, 2011 Surge had 56,096,547 common shares, 2,076,136 performance warrants and 3,081,666 options outstanding.

LIQUIDITY AND CAPITAL RESOURCES

On December 31, 2010, Surge had a net working capital deficit of $48.1 million including unrealized hedging losses of $2.6 million, as well as bank debt of $30 million.

Surge anticipates that future capital requirements will be funded through a combination of internal cash flow, divestitures, 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.

The Corporation has a $105.0 million extendible, revolving term credit facility with a Canadian bank bearing interest at bank rates. The facility is available on a revolving basis until July 13, 2011. On July 13, 2011, at the Corporation's discretion, the facilities are 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 bank. As the available lending limits of the facilities are based on the bank'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. Under the terms of the agreement, the Corporation is required to meet certain financial and engineering reporting requirements.

The Corporation defines net debt as outstanding bank plus or minus cash-based working capital:

NET DEBT **($000s)**	
Bank Debt	$(30,000)
Cash	1,437
Accounts receivable	12,404
Prepaid expenses and deposits	1,657
Accounts payable	(31,738)
Total	**$(46,240)**

The 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

Certain former officers and directors of the Corporation purchased 20,000 units for total gross proceeds of $60,000 as part of the January 19, 2010 equity offering.

Certain officers and directors of the Corporation purchased 1,099,413 common units, 661,951 flow-through units and 9,088 common shares as part of the April 13, 2010 private placement.

At December 31, 2009, two share purchase loans aggregating $360,000 were due from two former officers of the Corporation and had been deducted from share capital. The loans bore interest at a rate of 4.75 percent and were due on June 30, 2010. On April 13, 2010, the entire amount of the principal and interest outstanding has been repaid and the related common shares totaling 160,000 have been issued.

Surge was not involved in any off-balance-sheet transactions during the three months or year ended December 31, 2010 other than those mentioned under contracted obligations below.

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 service transport agreements totalling $9.5 million, as summarized below:

COMMITMENTS

($000s)	
2011	$ 1,599
2012	2,245
2013	1,611
2014	1,109
2015	960
2016+	2,019
Total	**$ 9,543**

In 2009, the Corporation issued a total of 757,000 flow-through common shares at $3.40 per share for gross proceeds of $2.6 million. The Corporation renounced these qualifying petroleum and natural gas expenditures on December 31, 2009. As at December 31, 2010, the Corporation had incurred the entire $2.6 million towards this flow-through share obligation and has satisfied the terms of this flow-through share offering.

In 2010, the Corporation issued a total of 681,819 flow-through common shares at $4.40 per share as part of a flow-through unit for gross proceeds of $3.0 million. The Corporation renounced these qualifying petroleum and natural gas expenditures effective December 31, 2010. As at December 31, 2010 Corporation had incurred $0.8 million towards this flow-through share obligation and has until December 31, 2011 to incur the $2.2 million of remaining expenditures.

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 gains (losses) on oil and gas commodity contracts for the year ended December 31, 2010:

FINANCIAL INSTRUMENTS

TERM	TYPE (FLOATING TO FIXED)	VOLUME	SWAP PRICE (SURGE RECEIVES) (C$)	INDEX (SURGE PAYS) (C$)	YEAR ENDED DEC 31, 2010 UNREALIZED GAINS (LOSSES) (C$000S)	YEAR ENDED DEC 31, 2010 REALIZED GAINS (LOSSES) (C$000S)
Jan 1 – Dec 31, 2010	Swap	2,000 GJs/d	$5.80	AECO Monthly Average	-	1,459
Apr 1 – Oct 31, 2010	Swap	1,000 GJs/d	$5.32	AECO Monthly Average	-	377
Nov 1, 2009 - Mar 31, 2010	Swap	500 GJs/d	$6.00	AECO Monthly Average	-	42
Jan 1 to Dec 31, 2011	Call	500 GJs/d	$6.55	AECO Monthly Average	(2)	-
Jan 1 to Dec 31, 2011	Put	500 GJs/d	$5.00	AECO Monthly Average	454	-
Mar 1, 2009 - Dec 31, 2010	Swap	750 GJs/d	$5.64	AECO Monthly Average	-	261
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$86.00	WTI - NYMEX	-	151
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$84.00	WTI - NYMEX	-	78
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$86.00	WTI - NYMEX	-	151
Jan 1 to Dec 31, 2010	Swap	200 bbls/d	$81.00	WTI - NYMEX	-	(63)
Feb 1 to Dec 31, 2010	Swap	100 bbls/d	$87.75	WTI - NYMEX	-	197
Feb 1 to Dec 31, 2010	Swap	100 bbls/d	$87.90	WTI - NYMEX	-	201
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$80.00	WTI - NYMEX	(1,247)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$96.55	WTI - NYMEX	415	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$80.00	WTI - NYMEX	(1,247)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$91.00	WTI - NYMEX	661	-
Jan 1 to Dec 31, 2011	Call	125 bbls/d	$78.40	WTI - NYMEX	(757)	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$85.50	WTI - NYMEX	(749)	-
Jan 1 to Dec 31, 2011	Put	250 bbls/d	$78.40	WTI - NYMEX	123	-
Total					(2,349)	2,854

The following table outlines the unrealized and realized loss on an interest rate swap contract for the year ended December 31, 2010:

TERM	TYPE (FLOATING TO FIXED)	AMOUNT (C$)	COMPANY FIXED INTEREST RATE (%)	COUNTER PARTY FLOATING RATE INDEX	YEAR ENDED DEC 31, 2010 UNREALIZED GAINS (LOSSES) (C$)	YEAR ENDED DEC 31, 2010 REALIZED LOSSES (C$)
Feb 24 – Apr 15, 2010	Swap	35,000,000	4.42 to 4.44	CAD-BA-CDOR	-	(60)

SUBSEQUENT EVENTS

Subsequent to December 31, 2010, the Corporation entered into seven financial oil contracts:

TERM	VOLUME	FLOOR PRICE (C$)	OTHER TERMS
Apr 1 to Dec 31, 2011	250 bbls/day	$80.00	Participation in 100% of the upside above $84.35 CDN per barrel.
Jul 1 to Dec 31, 2011	250 bbls/day	$90.00	Participation in upside above $90.00 CDN per barrel at a rate of 74%.
Jan 1 to Dec 31, 2012	250 bbls/day	$97.00	N/A
Jan 1 to Dec 31, 2012	250 bbls/day	$80.00	Participation in upside above $80.00 CDN per barrel at a rate of 75%.
Jan 1 to Dec 31, 2012	250 bbls/day	$90.00	Participation in upside above $90.00 CDN per barrel at a rate of 63%.
Jan 1 to Dec 31, 2012	250 bbls/day	$80.00	Participation in 100% of the upside above $89.95 CDN per barrel.
Jan 1 to Dec 31, 2012	500 bbls/day	$90.00	Participation in 68.5% of the upside above $90.00 CDN per barrel.

NEW ACCOUNTING PRONOUNCEMENTS

INTERNATIONAL FINANCIAL REPORTING STANDARD

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Surge's financial statements up to and including December 31, 2010 have been reported in accordance with Canadian GAAP as it existed on each reporting date. Financial statements for the quarter ended March 31, 2011, including comparative amounts, will be prepared on an IFRS basis.

A transition plan has been developed to convert the financial statements to IFRS. External advisors have been retained and will continue to assist management with the project on an as needed basis. Training has been provided to key employees and staff training programs will continue as needed. The Corporation continues to assess the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures.

Systems and controls are being updated as IFRS accounting processes are implemented. Significant system and control changes are not anticipated. The project team continues to provide updates to senior management and the Audit Committee. Calculations of the impact of changes in accounting policy have been prepared by management and have not been approved by the Corporation's Board of Directors or reviewed by the Corporation's auditors.

The Corporation's auditors have been involved throughout the process to ensure the Corporation's policies are in accordance with the new standards.

There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail below. Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet being January 1, 2010. In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First time adoption of IFRS" allowing additional exemptions for first-time adopters. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. Surge is planning to adopt this exemption. Management has analyzed the various other accounting policy choices available under IFRS 1 and has determined the following to be most appropriate for Surge:

- Oil and gas properties formerly classified as Property, Plant and Equipment ("PP&E") will be classified under IFRS as either Development and Production assets ("D&P") or Exploration and Evaluation assets ("E&E"). Upon transition to IFRS, Surge will reclassify all E&E expenditures included in the PP&E balance under Canadian GAAP, as a separate item under IFRS. These assets will be measured at cost and will not be depleted but will be assessed for impairment when indicators suggest the possibility of impairment. Once these E&E assets have reached technical feasibility and commercial viability, they will be transferred to D&P. At the time of transfer, they will be subjected to an impairment test. Surge's E&E assets will primarily consist of undeveloped exploration lands and at January 1, 2010 are estimated at $0.3 million.
- Under IFRS, D&P assets are grouped into areas designated as cash generating units ("CGU") for the purposes of impairment testing and further broken down into components within the CGU for purposes of depletion and depreciation. IFRS 1 provides for the allocation of the Canadian GAAP net book value of PP&E assets excluding E&E assets, to IFRS CGUs and components on a pro rata basis using the reserve volumes or values as at December 31, 2009. Surge has elected to allocate the D&P balance using reserve values and at January 1, 2010, the value allocated to the PP&E assets is approximately $126.5 million.
- Under IFRS, divestitures of an oil and gas property will generally result in a gain or loss recognized in earnings. Under Canadian GAAP, proceeds of divestitures are deducted from the full cost pool without recognition of a gain or loss unless such a deduction resulted in a change to the depletion rate of 20 percent or greater.
- Under Canadian GAAP, impairment testing on oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing will be performed at the CGU level. This will result in a greater number of impairment tests. At January 1, 2010, Surge did not have any impairment on its D&P assets under IFRS.
- Depletion and depreciation of D&P will be calculated at a component level. Depletion of resource properties within D&P will be calculated using the unit-of-production method under IFRS with the option to base the calculation on proved reserves or proved plus probable reserves. Surge will use proved plus probable reserves to calculate the depletion of resource properties. Surge expects that depletion expense for the year ended December 31, 2010 will be lower than currently reported under Canadian GAAP. Depreciation of office equipment will continue to be calculated using a declining balance method.
- IFRS 1 allows Surge to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations prior to transition on January 1, 2010. Surge will elect to use this exemption; therefore, Surge will not be recording any adjustments to retrospectively restate any of its business combinations that have occurred prior to January 1, 2010. Under IFRS reporting, Surge will restate two business combinations that occurred in each of the third and fourth quarters of 2010. Transaction costs capitalized under Canadian GAAP to PP&E are expensed under IFRS.
- Under Canadian GAAP, Surge's Asset Retirement Obligation is discounted over its life based on a credit adjusted risk free rate which was 7.7 percent at December 31, 2009. Under IFRS, Surge is required to revalue its liability for asset retirement costs at each balance sheet date using a risk-free discount rate. As a result, the Corporation's Asset Retirement Obligation will increase upon transition to IFRS as the liability will be re-valued using a discount rate of 4.00 percent to reflect the Corporation's estimated risk-free rate of interest. The revalued Asset Retirement Obligation at the transition date is estimated at $13.0 million, with a corresponding decrease in future tax of $2.0 million, the offsetting net increase in the liability of $5.0 million charged to retained earnings.

- Under IFRS, share-based payments are expensed based on a graded vesting schedule, which was also permitted under GAAP. Surge has historically recorded stock-based compensation using the graded method, which results in front loading of the expense. IFRS differs from GAAP in that the Corporation will also be required to incorporate a forfeiture multiplier rather than account for forfeitures as they occur as currently practiced under Canadian GAAP. The Corporation's historical forfeiture rate is close to zero percent, and therefore no opening balance sheet adjustment is anticipated.
- Under IFRS, risk-sharing agreements in which the Corporation cedes a portion of its working interest to a third-party are generally considered to be disposals of property, plant and equipment, potentially resulting in a gain or loss on disposition. Under the Corporation's existing Canadian GAAP, no gain or loss is recorded on these or other dispositions where the change in consolidated depletion is less than 20 percent. There is no equivalent exemption in IFRS. As a result, it is expected that the Corporation will record gains or losses on risk-sharing arrangements and other disposition transactions under IFRS. There is no impact on transition to IFRS as result of this requirement. Subsequent to transition, the significance of these gains or losses will be dependent on the details of specific transactions.
- Under Canadian GAAP, the future tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the future tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Corporation's common shares at the time of issue is recorded as a future tax expense as the expenditures are incurred. This future tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment results in an increase of $2.5 million, before the associated tax impact, to share capital with a resulting offset being charged to retained earnings.

In the first quarter of 2011, the Corporation plans to prepare its 2010 IFRS comparative quarterly financial statements and will assess and continue to review the impact of the IFRS changes on disclosure controls and internal controls, including identification of instances where controls may require amendments or additions in order to address the accounting policy changes required under IFRS. No material changes in control procedures are anticipated.

CRITICAL ACCOUNTING ESTIMATES

OIL AND NATURAL GAS RESERVES

Under National Instrument 51-101 (N.I. 51-101), "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable, i.e., that it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. In accordance with this definition, the level of certainty targeted by the reporting corporation should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of "probable" reserves, which are obviously less certain to be recovered than proved reserves, N.I. 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting corporation must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of N.I. 51-101 has resulted in a more rigorous and uniform standard of reserve evaluation.

The oil and natural gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Corporation's plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Corporation is described next under depletion expense and impairment of petroleum and natural gas properties.

DEPLETION EXPENSE

The Corporation uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of-production method based on estimated proved oil and natural gas reserves.

An increase or decrease in estimated proved oil and natural gas reserves would result in a corresponding reduction or increase in depletion expense. A decrease or increase in estimated future development costs would result in a corresponding reduction or increase in depletion expense.

WITHHELD COSTS

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted, which would increase depletion expense for the given period.

IMPAIRMENT OF PETROLEUM AND NATURAL GAS ASSETS

The Corporation is required to review the carrying value of all petroleum and natural gas assets for potential impairment. Impairment is indicated if the carrying value of the petroleum and natural gas assets is not recoverable by the future undiscounted funds from operations. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property, plant and equipment is charged to earnings. The assessment of impairment is dependent on estimates of reserves, production rates, prices, future costs and other relevant assumptions.

ASSET RETIREMENT OBLIGATIONS

The Corporation is required to provide for future removal and site restoration costs. The Corporation must estimate these costs in accordance with existing laws, contracts, or other policies. The fair value of the liability for the Corporation's asset retirement obligation is recorded in the period in which it is expected to be incurred, discounted to its present value using the Corporation's eight percent credit adjusted risk-free rate and two percent inflation rate. The offset to the liability is recorded in the carrying amount of petroleum and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of funds from operations or to the original estimated undiscounted cost could also result in an increase or decrease in the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

STOCK-BASED COMPENSATION

The Corporation uses the fair value method for valuing the stock option grants. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. A zero dividend yield is used as the Corporation does not issue dividends; the volatility is a calculation based on past trading history and the risk-free rate is from the Bank of Canada. An increase in dividends would decrease the option exercise and an increase in the volatility or the risk-free rate would increase the calculated expense.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINENT MATTERS

The Corporation is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can reasonably be estimated. When the loss is determined, it is charged to earnings.

The Corporation's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

INCOME TAX ACCOUNTING

The determination of the Corporation's income and other tax liabilities requires 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 may differ significantly from that estimated and recorded by management. In addition, the Corporation calculates future taxes based on rates substantively enacted at each reporting period and expected to apply when temporary differences reverse. Any changes in the anticipated reversals may impact future tax rates and the increase or decrease will be recorded through earnings.

FINANCIAL INSTRUMENTS

The Corporation recognizes the fair value for the unrealized portion of derivative contracts at each reporting date on the financial statements. The fair value is based on an estimate of the amounts that would have been paid to or received from counterparties to settle these instruments given future market prices and other relevant factors. As the fair value is based on a number of subjective estimates such as future prices and volatility in commodity markets, estimates could differ from actual results realized.

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.

MANAGEMENT'S LETTER

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the financial statements and other financial and operating data contained elsewhere in the report. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected with all information available up to April 26, 2011. The financial statements have been prepared using policies and procedures established by management in accordance with Canadian generally accepted accounting principles and reflect fairly Breaker's financial position, results of operations and cash flow.

KPMG LLP, independent auditors appointed by the shareholders, have examined the consolidated financial statements, and Sproule Associates Limited has reviewed the corporate reserves. Their examinations provide independent views as to the amounts and disclosures in the financial statements.

The Audit Committee, consisting exclusively of independent directors, has reviewed in detail the financial statements with management and the external auditors and has recommended their approval to the Board of Directors.

The Board of Directors has approved the financial statements and information as presented in this annual report.

P. Daniel O'Neil	Maxwell A. W. Lof
President and Chief Executive Officer	Chief Financial Officer

April 26, 2011

AUDITORS' REPORT

To the Shareholders of Surge Energy Inc.

We have audited the accompanying consolidated financial statements of Surge Energy Inc., which comprise the consolidated balance sheet as at December 31, 2010, the consolidated statements of operations, comprehensive loss and retained earnings, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Surge Energy Inc. as at December 31, 2010, and the results of its consolidated operations and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other Matter

The consolidated financial statements of Surge Energy Inc. as at and for the year ended December 31, 2009 were audited by another auditor who expressed an unmodified opinion on those statements on March 8, 2010 except as to note 13, which is as of March 25, 2010.

KPMG LLP

Chartered Accountants
Calgary, Canada

April 26, 2011

FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

Stated in Thousand of Dollars

	AS AT DECEMBER 31, 2010	2009
Assets		
Current Assets:		
Cash	**$ 1,437**	$ -
Accounts receivable	**12,404**	4,061
Prepaid expenses and deposits	**1,657**	1,536
Current future income taxes (note 9)	**681**	-
	16,179	5,597
Petroleum and natural gas properties (notes 4 and 5)	**361,398**	126,763
	$ 377,577	$ 132,360
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 31,738**	$ 10,628
Fair value of financial contracts (note 12)	**2,570**	221
Bank debt (note 6)	**-**	41,650
	34,308	52,499
Bank debt (note 6)	**30,000**	-
Future income taxes (note 9)	**35,239**	17,636
Asset retirement obligations (note 7)	**11,994**	5,389
Shareholders' equity:		
Share capital (note 8)	**227,434**	16,209
Contributed surplus (note 8)	**4,664**	3,559
Performance warrants (note 8)	**7,196**	-
Retained earnings	**26,742**	37,068
	266,036	56,836
Commitments (note 11)		
Subsequent events (note 13)		
	$ 377,577	$ 132,360

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board:

Keith MacDonald, Director

Peter Bannister, Director

CONSOLIDATED STATEMENT OF OPERATIONS, COMPREHENSIVE LOSS AND RETAINED EARNINGS

Stated in Thousands of Dollars, except per share amounts

	FOR THE YEARS ENDED DECEMBER 31, 2010	2009
Revenues		
Petroleum and natural gas	**$ 57,927**	$ 42,853
Royalties	**(8,122)**	(5,046)
Realized gain on financial contracts (note 12)	**2,794**	867
Unrealized loss on financial contracts (note 12)	**(2,349)**	(1,222)
	50,250	37,452
Expenses:		
Operating	**16,841**	13,042
Transportation	**2,426**	1,961
General and administrative	**6,185**	3,886
Stock-based compensation (note 8)	**5,351**	381
Interest expense	**998**	2,036
Bad debt provision	**506**	840
Depletion, depreciation and accretion	**23,681**	19,022
	55,988	41,168
Loss before the undernoted	**(5,738)**	(3,716)
Recapitalization costs	**5,409**	-
Loss before income taxes	**(11,147)**	(3,716)
Future income tax reduction (note 9)	**(821)**	(1,604)
Net loss and comprehensive loss	**(10,326)**	(2,112)
Retained earnings, beginning of year	**37,068**	39,219
Common shares repurchased and cancelled	**-**	(39)
Retained earnings, end of year	**$ 26,742**	$ 37,068
Loss per share (note 8)		
Basic	**$ (0.28)**	$ (0.13)
Diluted	**$ (0.28)**	$ (0.13)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Stated in Thousands of Dollars

	FOR THE YEARS ENDED DECEMBER 31,	
	2010	**2009**
Cash provided by (used in)		
Operating		
Loss including recapitalization costs of $5,409 for the year ended December 31, 2010	**$ (10,326)**	$ (2,112)
Depletion, depreciation and accretion	**23,681**	19,022
Future income tax reduction	**(821)**	(1,604)
Bad debt provision	**506**	840
Stock-based compensation	**5,351**	381
Unrealized loss on financial contracts	**2,349**	1,222
Abandonment expenditures	**(461)**	(257)
Change in non-cash working capital (note 10)	**(3,142)**	(1,151)
Cash flow from operating activities	**17,137**	16,341
Financing		
Bank debt	**(27,460)**	2,000
Issues of common shares and performance warrants, net of issue costs	**114,314**	3,511
Repurchase of common shares under normal course issuer bid	**-**	(66)
Cash flow from financing activities	**86,854**	5,445
Investing		
Petroleum and natural gas properties	**(41,996)**	(17,888)
Corporate acquistions (note 4)	**(1,009)**	-
Property acquisitions (note 4)	**(76,774)**	-
Proceeds on dispositions	**1,431**	-
Change in non-cash working capital (note 10)	**15,794**	(3,898)
Cash flow used in investing activities	**(102,554)**	(21,786)
Change in cash	**1,437**	**-**
Cash, beginning of year	**-**	-
Cash, end of year	**$ 1,437**	$ -
Interest paid	**$ 998**	$ 2,036

See note 10 for additional cash flow information.

Cash is defined as cash and cash equivalents.

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Surge Energy Inc. ("Surge" or the "Corporation"), formerly Zapata Energy Corporation, is incorporated under the laws of the Province of Alberta. The Corporation is engaged in the exploration for and development and production of oil and gas properties in western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Corporation, its wholly-owned subsidiaries and partnerships. All inter-entity transactions and balances have been eliminated.

(B) MEASUREMENT UNCERTAINTY

The consolidated financial statements of the Corporation have been prepared by management in accordance with Canadian generally accepted accounting principles. The preparation of these financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the amounts reported in the statements and accompanying notes. As a result, actual amounts could differ from estimated amounts. Specifically, the amounts recorded for depletion and depreciation of petroleum and natural gas properties, the provision for and accretion of asset retirement obligations and the ceiling test calculations are based on estimates of reserves, production rates, oil and natural gas prices, future development costs, salvage values and other relevant assumptions.

Assumptions used in the determination of the fair value of stock options and warrants issued are based on estimates of the future volatility of the Corporation's stock price, expected lives of the options and warrants, expected dividends and other relevant assumptions.

Future income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. The fair value of commodity contracts and the resultant unrealized gain (loss) on commodity contracts is based upon expected future commodity prices, interest rates and volatility in those prices and interest rates. These third-party prepared estimates are subject to change with fluctuations in commodity prices and interest rates.

By their nature, these estimates are subject to measurement uncertainty, and the effect of changes in estimates on the consolidated financial statements of future periods could be significant.

(C) CASH AND CASH EQUIVALENTS

Cash and cash equivalents are comprised of cash and all investments that are highly liquid in nature and have a maturity date of three months or less.

(D) PETROLEUM AND NATURAL GAS PROPERTIES

The Corporation follows the full cost method of accounting whereby all costs related to the acquisition of, exploration for and the development of petroleum and natural gas reserves are initially capitalized into a single Canadian cost center. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling productive and non productive wells, asset retirement costs, together with overhead and interest directly related to exploration and development activities, and lease and well equipment.

Proceeds from the disposal of properties are normally applied as a reduction of the cost of the remaining petroleum and natural gas properties, except when such a disposition would alter the rate of depletion and depreciation by more than 20%, in which case a gain or loss is recorded.

Costs capitalized are depleted using the unit-of-production method based on estimated proved petroleum and natural gas reserves before royalties as determined by independent engineers. For purposes of this calculation, petroleum and gas reserves are converted to a common unit of measure on the basis of their relative energy content, where six thousand cubic feet of gas equals one barrel of oil or liquids.

In determining its depletion base, the Corporation includes estimated future capital costs to be incurred in developing proved reserves and excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the unproved properties or impairment has occurred. Unproved properties are evaluated separately for impairment. When proved reserves are assigned to the property or the property is considered impaired, the cost of the property or the amount of impairment is added to the depletion base.

Other assets are depreciated using the declining balance method at annual rates of 20% to 100%.

Petroleum and natural gas properties are evaluated in each reporting period to determine whether the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amounts are assessed to be recoverable when the sum of undiscounted cash flows expected from proved reserves plus the cost of unproved properties net of impairment, exceeds the carrying amount of petroleum and natural gas properties. If the carrying amount is considered not recoverable, the magnitude of the impairment is measured by comparing the carrying amount of the petroleum and natural gas properties to the estimated, discounted future cash flows of the Corporation's proved plus probable reserves plus the cost of unproved properties, net of impairment. The future cash flows are discounted at the Corporation's risk-free interest rate and are based on forecast prices and costs, as provided by an independent third party. Any recognized impairment is recorded as additional depletion expense.

(E) ASSET RETIREMENT OBLIGATIONS

The estimated fair value of asset retirement obligations is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Corporation's credit-adjusted risk-free interest rate. The discounted obligations are initially capitalized as part of the carrying amount of the related petroleum and natural gas properties, and a corresponding liability is recognized. The increase in petroleum and natural gas properties is depleted and depreciated on the same basis as the remainder of the petroleum and natural gas properties. The liability is accreted against income until it is settled or the property is sold and is recorded as accretion expense. Revisions to the estimated timing of cash flows or the cost estimates could also result in an increase or decrease to the obligation. Actual restoration expenditures are charged to accumulated obligations as incurred to the extent of the liability recorded.

(F) INTEREST IN JOINT OPERATIONS

A portion of the Corporation's exploration and production activities are conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Corporation's proportionate interest in such activities.

(G) FUTURE INCOME TAXES

Income taxes are accounted for using the asset and liability method of income tax allocation. Under the asset and liability method, future income tax assets and liabilities are recorded based on the difference between the tax basis of an asset or liability and the carrying amount on the balance sheet. Future income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities. Future income tax assets and liabilities are determined based on the tax laws and substantively enacted rates in effect. Actual rates in effect when the differences are expected to reverse may differ substantially as a result of changes to tax legislation. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(H) STOCK-BASED COMPENSATION AND WARRANT VALUATION

The Corporation uses the fair value method for valuing stock options and warrants. Under the fair value method, compensation costs attributable to all stock options and warrants granted are measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase to contributed surplus or warrants. The fair value of each option or warrant granted is estimated using the Black-Scholes option pricing model that takes into account the grant date, the exercise price and expected life of the option or warrant, the price of the underlying security, the expected volatility, the risk-free interest rate and dividends if any on the underlying security. Upon the exercise of the stock options and warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital and the contributed surplus or warrants balance is reduced.

The Corporation has not incorporated an estimated forfeiture rate for stock options or warrants that will not vest, rather, the Corporation accounts for actual forfeitures as they occur.

(I) REVENUE RECOGNITION

Revenue from the sale of petroleum and natural gas is recorded on a gross basis when title passes to an external party and collection is reasonably assured based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including production costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(J) PER SHARE INFORMATION

Per share amounts are calculated based on the weighted average number of common shares outstanding during the year. The diluted weighted average number of shares is adjusted for the dilutive effect of options and warrants. Under the treasury stock method, only "in the money" options and warrants are included in the weighted average diluted number of shares. It is also assumed that any proceeds obtained upon the exercise of options and warrants plus the unamortized portion of stock-based compensation would be used to purchase common shares at the average price during the period. The weighted average number of shares is then reduced by the number of shares acquired.

(K) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to subscribers. To recognize the foregone tax benefits to the Corporation, share capital is reduced and a future tax liability is recorded equal to the estimated amount of future income taxes payable when the income tax deduction is renounced.

(L) FINANCIAL INSTRUMENTS

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

The Corporation has designated its cash and cash equivalents as held for trading which are measured at fair value with changes in those fair values recognized in net earnings. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other liabilities which are measured at amortized cost which is determined using the effective interest rate method. The Corporation enters into forward swap, collar or put agreements to manage its exposure to the risks associated with fluctuating oil and gas prices and interest rates.

The Corporation has policies and procedures in place with respect to the required documentation and approvals for the use of derivative financial instruments. All transactions of this nature entered into by the Corporation are related to future oil and gas production or anticipated debt levels. Derivative financial instruments are used by the Corporation to manage exposure to fluctuating commodity prices and interest rates and are not used for speculative or trading purposes. The Corporation has elected not to designate these derivative instruments as hedges for accounting purposes. As a result, all derivative financial instruments are recorded on a mark-to-market basis or fair valued with the resulting gains or losses taken into income. The fair value of these derivative financial instruments are based on an estimate of the amount that would have been recovered or paid to settle these instruments prior to maturity given market prices and other relevant factors.

The Corporation has elected to account for its physical delivery commodity sales contracts and other non-financial contracts held for the purpose of receipt or delivery of non-financial items in accordance with the expected purchase, sale or usage requirements on an accrual basis. The Corporation measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value. The Corporation nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank debt is presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

(M) COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with current year's presentation.

3. FUTURE ACCOUNTING POLICIES

Adoption of International Financial Reporting Standards ("IFRS")

On January 1, 2011 International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board, will become the generally accepted accounting principles in Canada. The transition from Canadian GAAP to IFRS will result in significant differences affecting financial position and results of operations. The Corporation will be reporting under IFRS for all periods beginning after January 1, 2011 and will be required to restate comparative information for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

4. ACQUISITIONS

(A) CORINTHIAN ENERGY CORP.

Effective July 9, 2010, the Corporation acquired all of the issued and outstanding common shares of Corinthian Energy Corp. ("Corinthian"), a privately held junior oil and gas exploration company, in exchange for 16,025,529 common shares of Surge with an assigned value of $94,477,000. The common shares have been ascribed a fair value of $5.90 per common share issued, as determined based on the Corporation's weighted average trading price at the date of announcement being June 22, 2010. In addition, Surge incurred transaction costs of $1,009,000. The operations of Corinthian have been included in the results of Surge commencing July 9, 2010. The transaction was accounted for by the purchase method. The allocation of the purchase price for the acquisition has not been finalized. The following amounts are estimates based on information available at the time of preparation of these financial statements. Accordingly, these amounts are subject to changes as cost estimates and values are finalized. The preliminary allocation of the purchase price, based on management's estimates of fair values, is as follows:

FAIR VALUE OF NET ASSETS ACQUIRED:	
Petroleum and natural gas properties	$ 133,255
Bank debt	(15,810)
Working capital	472
Asset retirement obligations	(4,959)
Future income tax liability	(17,472)
Net assets acquired	**$ 95,486**
Consideration:	
Common shares (16,025,529 common shares)	$ 94,477
Transaction costs	1,009
Total consideration	$ 95,486

(B) CRYSTAL LAKE RESOURCES LTD.

Effective July 19, 2010, Surge acquired all of the issued and outstanding common shares of Crystal Lake Resources Ltd. ("Crystal Lake"), a privately held junior oil and gas exploration company, in exchange for 288,639 common shares of Surge with an assigned value of $1,702,000. The common shares have been ascribed a fair value of $5.90 per common share issued, as determined based on the Corporation's weighted average trading price at the date of announcement being June 22, 2010. The operations of Crystal Lake have been included in the results of Surge commencing July 19, 2010. The transaction was accounted for by the purchase method. The allocation of the purchase price for the acquisition has not been finalized. The following amounts are estimates based on information available at the time of preparation of these financial statements. Accordingly, these amounts are subject to changes as cost estimates and values are finalized. The preliminary allocation of the purchase price, based on management's estimates of fair values, is as follows:

FAIR VALUE OF NET ASSETS ACQUIRED:	
Petroleum and natural gas properties	$ 1,675
Working capital	40
Asset retirement obligations	(90)
Future income tax liability	77
Net assets acquired	**$ 1,702**
Consideration:	
Common shares (288,639 common shares)	$ 1,702
Total consideration	$ 1,702

(C) VALHALLA PROPERTY ACQUISITION

Effective November 1, 2010, Surge acquired certain petroleum and natural gas properties in the Valhalla region of Alberta, in exchange for cash of $74.5 million with associated asset retirement obligations of $1.1 million.

5. PETROLEUM AND NATURAL GAS PROPERTIES

DECEMBER 31, 2010	Cost	Accumulated Depletion	Net Book Value
Petroleum and natural gas properties	$ 487,055	$ 125,657	$ 361,398

December 31, 2009	Cost	Accumulated Depletion	Net Book Value
Petroleum and natural gas properties	$ 229,352	$ 102,589	$ 126,763

During the year ended December 31, 2010, the Corporation capitalized $2.4 million (2009 - $0.02 million) of overhead-related costs to petroleum and natural gas properties. In addition, $3.0 million in stock-based compensation and the related tax impact of $1.0 million was capitalized during the year ended December 31, 2010.

Costs associated with unproven properties, salvage values and seismic excluded from costs subject to depletion as at December 31, 2010 totaled $107.1 million (2009 – $7.6 million). Future development costs for proved reserves of $63.8 million (2009 – $16.8 million) have been included in the depletion calculation.

During 2010, the Corporation disposed of certain interests in petroleum and natural gas properties for cash proceeds of $1.4 million, with associated asset retirement obligations of $0.1 million also eliminated.

The Corporation performed a ceiling test calculation at December 31, 2010 to assess the recoverable value of the petroleum and natural gas assets. As at December 31, 2010 there was no impairment required. For purposes of the ceiling test calculation, the Corporation used the January 1, 2011 commodity price forecast of its independent reserve evaluators. The following table summarizes the benchmark prices used in the calculation:

	MEDIUM AND LIGHT CRUDE OIL			NATURAL GAS	NGL			
YEAR	WTI CUSHING OKLAHOMA 40˚ API (US$/BBL)	EDMONTON PAR PRICE 40˚ API ($/BBL)	CROMER MEDIUM 29.3˚ API ($/BBL)	AECO GAS PRICE ($/MMBTU)	PENTANES PLUS FOB FIELD GATE ($/BBL)	BUTANES FOB FIELD GATE ($/BBL)	INFLATION RATES (%/YR)	EXCHANGE RATE ($US/$CDN)
2011	88.40	93.08	85.63	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	86.34	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	85.02	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	84.18	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	85.45	6.69	97.24	63.69	1.5	0.932
2016	91.57	96.38	86.74	6.80	98.70	64.65	1.5	0.932
2017	92.94	97.84	88.05	6.91	100.18	65.62	1.5	0.932
2018	94.34	99.32	89.38	7.02	101.68	66.60	1.5	0.932
2019	95.75	100.81	90.73	7.14	103.21	67.60	1.5	0.932
2020	97.19	102.34	92.10	7.26	104.76	68.61	1.5	0.932

6. BANK DEBT

The Corporation has a $105.0 million extendible, revolving term credit facility with a Canadian bank bearing interest at bank rates. The facility is available on a revolving basis until July 13, 2011. On July 13, 2011, 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 bank. As the available lending limits of the facilities are based on the bank'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 1.25 percent as at December 31, 2010 (2009 – prime plus 1.25 percent).

The 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. Under the terms of the agreement, the Corporation is required to meet certain financial and engineering reporting requirements.

Under the terms of the agreement, the Corporation must maintain an adjusted working capital ratio of not less than 1.00:1.00 at all times. The working capital ratio is defined under the current credit facility as current assets, including the undrawn portion of the facility, to current liabilities, excluding any current bank indebtedness. The Corporation is compliant with this covenant at December 31, 2010.

7. ASSET RETIREMENT OBLIGATIONS

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $74.3 million (2009 – $19.7 million) which will be incurred between 2011 and 2059. The majority of these costs will be incurred between 2011 and 2037. A credit-adjusted risk free rate of eight percent (2009 – eight percent) and an inflation rate of two percent (2009 – two percent) was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	YEARS ENDED DECEMBER 31,	
	2010	**2009**
Balance, beginning of year	**$ 5,389**	$ 5,243
Liabilities related to acquisitions (note 4)	**6,162**	-
Liabilities related to dispositions (note 5)	**(51)**	-
Liabilities incurred	**342**	(1)
Accretion expense	**613**	404
Abandonment expenditures	**(461)**	(257)
Balance, end of year	**$ 11,994**	$ 5,389

8. SHARE CAPITAL

(A) AUTHORIZED

Unlimited number of voting common shares.

Unlimited number of preferred shares, issuable in series.

(B) ISSUED AND OUTSTANDING

	NUMBER OF SHARES	AMOUNT
Common Shares:		
Balance, December 31, 2008	16,697,811	$ 12,641
Issued pursuant to unit offering	417,466	1,252
Issued pursuant to flow-through offering	757,000	2,574
Share issue costs	-	(315)
Tax effect of share issue costs	-	84
Shares purchased pursuant to a normal course issuer bid	(36,000)	(27)
Balance, December 31, 2009	**17,836,277**	**$ 16,209**
Issued pursuant to unit offering	926,933	2,781
Issued pursuant to private placement	3,863,636	14,716
Issued pursuant to short form prospectus	6,945,000	50,004
Issued pursuant to Corinthian acquisition (note 4)	16,025,529	94,477
Issued pursuant to Crystal Lake acquisition (note 4)	288,639	1,702
Issued pursuant to short form prospectus	8,001,000	42,005
Share issue costs	-	(5,029)
Tax effect of share issue costs	-	1,359
Exercise of stock options	1,535,334	6,865
Exercise of warrants	672,199	2,689
Stock-based compensation of flow-through units	-	331
Tax effect of flow-through shares issued in 2009	-	(675)
Balance, December 31, 2010	**56,094,547**	**$ 227,434**

On January 19, 2010, the Corporation issued 848,600 units at a price of $3.00 per unit, with each unit consisting of one common share and one-half of a common share purchase warrant (with each whole warrant exercisable into one common share at a price of $4.00 per share until December 23, 2010), for total gross proceeds of $2,545,800. Certain former officers and directors purchased 20,000 units for total gross proceeds of $60,000.

On January 29, 2010, the Corporation issued 78,333 units at a price of $3.00 per unit, with each unit consisting of one common share and one-half of a common share purchase warrant (with each whole warrant exercisable into one common share at a price of $4.00 per share until December 23, 2010), for total gross proceeds of $235,000.

On April 13, 2010, pursuant to a private placement, the new management group, together with certain additional subscribers identified by the new management group, subscribed for 1,394,317 common units of the Corporation at a price of $4.40 per common unit, 1,787,500 common shares of the Corporation at a price of $4.40 per common share and 681,819 flow-through units at a price of $4.40 per flow-through unit, for total proceeds to the Corporation of approximately $17,000,000. Each common unit is comprised of one common share and one common share performance warrant, entitling the holder to purchase one common share at a price of $5.17 for a period of five years. Each flow-through unit is comprised of one common share issued on a flow-through basis pursuant to the Income Tax Act of Canada and one common share performance warrant, also entitling the holder to purchase one common share at a price of $5.17 for a period of five years. The common and flow-through shares issued as part of the common and flow-through units were ascribed a value of $3.30 per share or $6,851,000 due to the escrow restrictions described below. For further details on the vesting conditions and valuation of the common share performance warrants, please refer to note 8(d). The Corporation also recorded $331,000 of stock-based compensation on the flow-through units. Certain officers and directors of the Corporation purchased 1,099,413 common units, 661,951 flow-through units and 9,088 common shares as part of the private placement.

All of the units issued were acquired by contractors, employees, officers or directors of the Corporation ("deemed service providers"). For deemed service providers, units acquired through the private placement are held under an escrow agreement in which one-third of the units are to be released equally every six months following the date of issuance. No securities will be released from escrow after the date the deemed service provider ceases to be a service provider, unless directed by a resolution of the Board of Directors. Upon the deemed service provider ceasing to be a service provider, Surge will repurchase for cancellation or provide for a transfer to another deemed service provider all of the securities of the deemed service provider then held in escrow at a price equal to the lessor of $4.40 per unit and the market price of the common shares of Surge on the last day of trading immediately prior to the deemed service provider ceasing to be a service provider.

On May 5, 2010, the Corporation issued 6,945,000 common shares at a price of $7.20 per share for gross proceeds of $50,004,000, pursuant to a short form prospectus.

On November 1, 2010, the Corporation issued 8,001,000 common shares at a price of $5.25 per share for gross proceeds of $42.0 million. The proceeds were used to partially fund the Valhalla acquisition (note 4).

During the year ended December 31, 2010, two share purchase loans aggregating $360,000 due from two former officers of the Corporation were repaid. The loans bore interest at a rate of 4.75 percent and were due on June 30, 2010. The entire amount of the principal and interest outstanding has been repaid and the related common shares totaling 160,000 were issued. The 160,000 shares attributable to the share purchase loans had been included in the stock options and are shown as part of the stock options exercised balance below.

(C) STOCK OPTIONS

Under the Corporation's stock option plan, it may grant options to its employees for up to 5,609,455 common shares of the Corporation as at December 31, 2010. The exercise price of each option equals the market price of the Corporation's common shares at the date of grant. Options granted have a term of five years to maturity and vest as to one-third on each of the first, second and third anniversaries from the date of grant.

	YEAR ENDED DECEMBER 31, 2010		YEAR ENDED DECEMBER 31, 2009	
	NUMBER OF OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Stock options oustanding, beginning of year	**1,878,001**	**$ 3.74**	1,643,666	$ 3.87
Granted	**2,636,000**	**$ 6.38**	345,000	$ 3.20
Exercised	**(1,535,334)**	**$ 3.17**	-	$ -
Forfeited	**(295,000)**	**$ 6.61**	(110,665)	$ 4.04
Stock options oustanding, end of year	**2,683,667**	**$ 6.24**	1,878,001	$ 3.74
Exercisable at year-end	**99,666**	**$ 2.59**	1,408,337	$ 4.07

	Year ended December 31, 2010				
	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Outstanding	Weighted Average Exercise Price	Weighted Average Contractual Life (Years)	Number Exercisable	Weighted Average Exercise Price
$1.00 - $2.79	46,666	$ 1.75	2.95	46,666	$ 1.75
$2.80 - $4.59	51,000	$ 3.19	3.91	51,000	$ 3.19
$4.60 - $6.39	610,501	$ 5.77	4.60	-	$ -
$6.40 - $8.19	1,975,500	$ 6.57	4.56	2,000	$ 7.10
$1.00 - $8.19	2,683,667	$ 6.24	4.53	99,666	$ 2.59

(D) PERFORMANCE WARRANTS

As part of the private placement completed on April 13, 2010, 2,076,136 performance warrants were issued with an exercise price of $5.17 as part of the common share and flow-through units. The performance warrants vest and become exercisable as to one-third upon the 20 day weighted average trading price of the common shares equaling or exceeding $5.69, an additional one-third upon the trading price equaling or exceeding $6.20 and a final one-third upon the trading price equaling or exceeding $6.72. The performance warrants are released from escrow one third on each of the six, twelve and eighteen month anniversaries from the date of grant.

The performance warrants expire on April 13, 2015. As at December 31, 2010, all 2,076,136 performance warrants were outstanding, vested and two-thirds held in escrow.

A Black-Scholes derived fair value of $3.47 per warrant, or $7,196,000 was assigned to the performance warrants. As the consideration received on the common and flow-through units of $4.40 per share, or $9,135,000 was less than the total fair values ascribed to the common and flow-through shares ($6,851,000) and the performance warrants ($7,196,000) of $14,047,000, an additional stock-based compensation cost of $4,912,000 was recognized in the year.

(E) STOCK PURCHASE WARRANTS

As part of equity financings completed in December 2009 and January 2010, the Corporation issued 672,199 warrants exercisable immediately at an exercise price of $4.00 and with an expiry date of December 23, 2010. During the year ended December 31, 2010, all warrants were exercised.

(F) STOCK-BASED COMPENSATION

A reconciliation of the stock-based compensation expense is provided below:

	Years ended December 31,	
	2010	2009
Stock-based compensation on options	**$ 3,106**	$ 381
Stock-based compensation on performance warrants (note 8(d))	**4,912**	-
Stock-based compensation on flow-through share premiums (note 8(b))	**331**	-
Capitalized stock-based compensation	**(2,998)**	-
Total stock-based compensation expense	**$ 5,351**	$ 381

The Corporation's stock-based compensation expense for the year ended December 31, 2010 was $5.4 million (2009 - $0.4 million). A Black-Scholes valuation model was applied to determine the fair value the options and performance warrants.

The following assumptions were used to calculate stock-based compensation on options granted for the year ended December 31, 2010: zero dividend yield (2009 – zero); expected volatility of 69 percent (2009 – 69 percent); risk free rate of 2 percent (2009 – 2 percent); and expected life of five years (2009 – 5 years). The weighted average fair value of options granted in 2010 is $3.79 per option (2009 - $1.52).

The following assumptions were used to calculate stock-based compensation on performance warrants issued in 2010: zero dividend yield; expected volatility of 69 percent; risk free rate of three percent; and expected life of five years. The weighted average fair value of performance warrants issued in 2010 is $3.47 per performance warrant.

(G) CONTRIBUTED SURPLUS

	YEARS ENDED DECEMBER 31,	
	2010	**2009**
Balance, beginning of year	**$ 3,559**	$ 3,178
Stock-based compensation on options	**3,106**	381
Transfer on exercise of stock options	**(2,001)**	-
Balance, end of year	**$ 4,664**	$ 3,559

(H) PER SHARE AMOUNTS

The following table summarizes the shares used in calculating the loss per share:

	YEARS ENDED DECEMBER 31,	
	2010	**2009**
Weighted average number of shares - basic and diluted	**36,467,864**	16,699,721

In computing diluted per share amount at December 31, 2010, 2,683,667 options (2009 – 1,878,001) and 2,076,136 performance warrants were excluded from the calculation as their effect was anti-dilutive.

9. INCOME TAXES

Significant components of the Corporation's future income tax liability are as follows:

	YEARS ENDED DECEMBER 31,	
	2010	**2009**
Petroleum and natural gas properties	**$ 32,413**	$ 15,680
Asset retirement obligations	**(2,999)**	(1,412)
Fair value of financial contracts	**(681)**	-
Deferred partnership income	**11,822**	3,535
Non-capital losses	**(4,431)**	-
Other	**(1,566)**	(167)
	$ 34,558	$ 17,636

The Corporation has recognized the benefit of $16.7 million of non-capital losses which are available to carry forward to reduce future taxable income in future years. These losses expire between 2013 and 2029.

Income tax recovery differs from that which would be expected from applying the combined effective Canadian federal and provincial corporate tax rates of 28 percent (2009 - 29 percent) to the loss before income taxes as follows:

	YEARS ENDED DECEMBER 31,	
	2010	2009
Loss before income taxes	**$ (11,147)**	$ (3,716)
Combined federal and provincial statutory rate	**28%**	29%
Expected income tax recovery	**$ (3,121)**	$ (1,078)
Difference resulting from:		
Changes in tax rates	**116**	(607)
Non-deductible stock-based compensation costs	**1,498**	110
Other	**686**	(29)
	$ (821)	$ (1,604)

10. CASH FLOW INFORMATION

	YEARS ENDED DECEMBER 31,	
	2010	2009
Accounts receivable	**(8,849)**	539
Prepaid expenses and deposits	**(121)**	(61)
Accounts payable and accrued liabilities	**21,110**	(5,527)
Working capital acquired on acquisitions (note 4)	**512**	-
Change in non-cash working capital	**12,652**	(5,049)
These changes relate to the following activities		
Operating	**(3,142)**	(1,151)
Investing	**15,794**	(3,898)
	12,652	(5,049)

11. COMMITMENTS

(A) FUTURE MINIMUM PAYMENTS RELATING TO OPERATING LEASE AND FIRM TRANSPORT COMMITMENTS

2011	$ 1,599
2012	2,245
2013	1,611
2014	1,109
2015	960
2016+	2,019
Total	**$ 9,543**

(B) FLOW-THROUGH SHARES

In 2009, the Corporation issued a total of 757,000 flow-through common shares at $3.40 per share for gross proceeds of $2.6 million. The Corporation renounced these qualifying petroleum and natural gas expenditures on December 31, 2009. As at December 31, 2010, the Corporation had incurred the entire $2.6 million towards this flow-through share obligation and has satisfied the terms of this flow-through share offering.

In 2010, the Corporation issued a total of 681,819 flow-through common shares at $4.40 per share as part of a flow-through unit for gross proceeds of $3.0 million. The Corporation renounced these qualifying petroleum and natural gas expenditures effective December 31, 2010. As at December 31, 2010 Corporation had incurred $0.8 million towards this flow-through share obligation and has until December 31, 2011 to incur the $2.2 million of remaining expenditures.

12. FINANCIAL INSTRUMENTS OVERVIEW

The Corporation has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Corporation's exposure to each of the above risks, the Corporation's objectives, policies and processes for measuring and managing risk, and the Corporation's management of capital. Further quantitative disclosures are included throughout these financial statements. The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's risk management framework. The Board has implemented and monitors compliance with risk management policies. The Corporation's risk management policies are established to identify and analyze the risks faced by the Corporation, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Corporation's activities.

(A) CREDIT RISK

Credit risk is the risk of financial loss to the Corporation if a customer or counter party to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables from joint venture partners and petroleum and natural gas marketers. As at December 31, 2010, the Corporation's receivables consisted of $8.2 million due from petroleum and natural gas marketers and $4.2 million due from joint venture partners. These amounts are presented net of the allowance for doubtful accounts.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Corporation attempts to mitigate credit risk by establishing marketing relationships with a variety of purchasers.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Corporation attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Corporation does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however the Corporation does have the ability to withhold production from joint venture partners in the event of non-payment.

The carrying value of cash and accounts receivable represent the maximum credit exposure. The Corporation has an allowance for doubtful accounts of $0.5 million (2009 - $4.0 million) at December 31, 2010. During the year ended December 31, 2010, the Corporation allowed for $0.5 million of bad debts (2009 – $0.8 million) and applied $4.0 million of its allowance for doubtful accounts against outstanding receivables.

As at December 31, 2010, the Corporation estimates its total accounts receivables, net of the allowance for doubtful accounts, to be aged as follows:

YEAR ENDED	TOTAL RECEIVABLE ($000s)	CURRENT	PAST DUE
December 31, 2010	**$ 12,404**	**$ 11,181**	**$ 1,223**
	100%	**90%**	**10%**
December 31, 2009	$ 4,061	$ 2,641	$ 1,420
	100%	65%	35%

(B) LIQUIDITY RISK

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation actively manages its liquidity through cost control, debt and equity management policies. Such strategies include continuously monitoring forecast and actual cash flows, financing activities and available credit under existing banking arrangements. The nature of the oil and gas industry is very capital intensive. As a result, the Corporation prepares annual capital expenditure budgets and utilizes authorizations for expenditures for projects to manage capital expenditures. Management believes that future cash flows generated in the ordinary course of business will be adequate to settle the Corporation's liabilities as they come due.

Accounts payable are considered due to suppliers in one year or less while bank debt, which is subject to a renewal after a 364-day revolving period, could be potentially due within the next year if the facility is not renewed for a further 364-day period. Financial contracts are also due to be settled with the counter-parties in one year at the estimated fair value on the balance sheet.

(C) MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Corporation's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Corporation utilizes financial derivative contracts to manage market risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

(I) FOREIGN CURRENCY EXCHANGE RISK

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange risks. Although substantially all of the Corporation's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar.

The Corporation had no forward exchange rate contracts in place as at or during the years ended December 31, 2010 and 2009.

(II) COMMODITY PRICE RISK

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices.

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices. Management continuously monitors commodity prices and initiates instruments to manage exposure to these risks when it deems appropriate. As a means of managing commodity price volatility, the Corporation enters into various derivative financial instrument agreements and physical contracts.

The following table outlines the realized and unrealized losses on oil and gas commodity contracts for the year ended December 31, 2010:

TERM	TYPE (FLOATING TO FIXED)	VOLUME	SWAP PRICE (SURGE RECEIVES) (C$)	INDEX (SURGE PAYS) (C$)	YEAR ENDED DEC 31, 2010 UNREALIZED GAINS (LOSSES) (C$000S)	YEAR ENDED DEC 31, 2010 REALIZED GAINS (LOSSES) (C$000S)
Jan 1 – Dec 31, 2010	Swap	2,000 GJs/d	$5.80	AECO Monthly Average	-	1,459
Apr 1 – Oct 31, 2010	Swap	1,000 GJs/d	$5.32	AECO Monthly Average	-	377
Nov 1, 2009 - Mar 31, 2010	Swap	500 GJs/d	$6.00	AECO Monthly Average	-	42
Jan 1 to Dec 31, 2011	Call	500 GJs/d	$6.55	AECO Monthly Average	(2)	-
Jan 1 to Dec 31, 2011	Put	500 GJs/d	$5.00	AECO Monthly Average	454	-
Mar 1, 2009 - Dec 31, 2010	Swap	750 GJs/d	$5.64	AECO Monthly Average	-	261
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$86.00	WTI - NYMEX	-	151
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$84.00	WTI - NYMEX	-	78
Jan 1 to Dec 31, 2010	Swap	100 bbls/d	$86.00	WTI - NYMEX	-	151
Jan 1 to Dec 31, 2010	Swap	200 bbls/d	$81.00	WTI - NYMEX	-	(63)
Feb 1 to Dec 31, 2010	Swap	100 bbls/d	$87.75	WTI - NYMEX	-	197
Feb 1 to Dec 31, 2010	Swap	100 bbls/d	$87.90	WTI - NYMEX	-	201
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$80.00	WTI - NYMEX	(1,247)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$96.55	WTI - NYMEX	415	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$80.00	WTI - NYMEX	(1,247)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$91.00	WTI - NYMEX	661	-
Jan 1 to Dec 31, 2011	Call	125 bbls/d	$78.40	WTI - NYMEX	(757)	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$85.50	WTI - NYMEX	(749)	-
Jan 1 to Dec 31, 2011	Put	250 bbls/d	$78.40	WTI - NYMEX	123	-
Total					(2,349)	2,854

(III) INTEREST RATE RISK

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Over the course of the year ended December 31, 2010, the Corporation was exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest. As at December 31, 2010, if interest rates had been 100 basis points lower with all other variables held constant, net earnings for year ended would have been approximately $0.2 million (2009 - $0.4 million) higher, due to lower interest expense. An equal and opposite impact would have occurred to net earnings had interest rates been 100 basis points higher.

The following table outlines the unrealized and realized loss on an interest rate swap contract for the year ended December 31, 2010:

TERM	TYPE (FLOATING TO FIXED)	AMOUNT (C$)	COMPANY FIXED INTEREST RATE (%)	COUNTER PARTY FLOATING RATE INDEX	YEAR ENDED DEC 31, 2010 UNREALIZED GAINS (LOSSES) (C$)	YEAR ENDED DEC 31, 2010 REALIZED LOSS (C$)
Feb 24 – Apr 15, 2010	Swap	35,000,000	4.42 to 4.44	CAD-BA-CDOR	-	(60)

The following table summarizes the sensitivity of the fair value of the Corporation's market risk management positions to fluctuations in both crude oil and natural gas prices. Both such fluctuations were evaluated independently, with all other variables held constant. In assessing the potential impact of these fluctuations, the Corporation believes that the volatilities presented below are reasonable measures. Fluctuations in crude oil and natural gas prices, which would impact the mark-to-market calculation of commodity contracts, could have had the following impact on the net earnings:

	NET EARNINGS IMPACT FOR YEAR ENDED DECEMBER 31, 2010	
	PRICE INCREASE	PRICE DECREASE
Crude Oil - Change of +/- $1.00	$ (212,156)	$ 212,156
Natural Gas - Change of +/- $0.50	$ (75,731)	$ 75,731

(D) CAPITAL MANAGEMENT

The Corporation's policy is to maintain a strong capital base so as to maintain investor, creditor, and market confidence and sustain the future development of the business. The Corporation manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Corporation considers its capital structure to include shareholder's equity of $266.0 million (2009 - $56.8 million), bank debt of $ 30.0 million (2009 - $41.7 million) and a working capital deficiency excluding bank debt of $18.1 million (2009 – $5.3 million). In order to maintain or adjust capital structure, the Corporation may from time to time issue shares and adjust its capital spending to manage current and projected debt levels.

The Corporation monitors its capital based on the ratio of forecast net debt to forecast funds from operations. Net debt is defined as outstanding bank debt plus or minus cash-based working capital. Funds from operations is defined as cash flow from operating activities before changes in non-cash working capital. The Corporation's strategy is to maintain a one year forward looking forecast debt to forecast funds from operations ratio of less than two to one. This ratio may increase at certain times as a result of acquisitions or other capital spending. In order to facilitate the management of this ratio, the Corporation prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

(E) FAIR VALUE OF FINANCIAL INSTRUMENTS

The Corporation's financial instruments as at December 31, 2010 and 2009 include cash, accounts receivable, accounts payable and accrued liabilities, the fair value of financial contracts and bank debt. The fair value of cash, accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to their short-terms to maturity.

The fair value of financial contracts is determined by discounting the difference between the contracted commodity price/interest rate and published forward commodity price/interest rate curves as at the balance sheet date, using the remaining contracted notional volumes.

Bank debt, when outstanding, bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

The Corporation classifies its financial instruments recorded at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Corporation's financial contracts are considered level 2, while cash is considered level 1.

13. SUBSEQUENT EVENTS

Subsequent to December 31, 2010, the Corporation entered into seven financial oil contracts:

TERM	VOLUME	FLOOR PRICE (C$)	OTHER TERMS.
Apr 1 to Dec 31, 2011	250 bbls/day	$80.00	Participation in 100 percent of the upside above $84.35 CDN per barrel.
Jul 1 to Dec 31, 2011	250 bbls/day	$90.00	Participation in upside above $90.00 CDN per barrel at a rate of 74 percent.
Jan 1 to Dec 31, 2012	250 bbls/day	$97.00	N/A
Jan 1 to Dec 31, 2012	250 bbls/day	$80.00	Participation in upside above $80.00 CDN per barrel at a rate of 75 percent.
Jan 1 to Dec 31, 2012	250 bbls/day	$90.00	Participation in upside above $90.00 CDN per barrel at a rate of 63 percent.
Jan 1 to Dec 31, 2012	250 bbls/day	$80.00	Participation in 100 percent of the upside above $89.95 CDN per barrel.
Jan 1 to Dec 31, 2012	500 bbls/day	$90.00	Participation in 68.5 percent of the upside above $90.00 CDN per barrel.

CORPORATE INFO

DIRECTORS

Paul Colborne (Chairman)(4)

Peter Bannister(1)(2)

Dan O'Neil

Robert Leach(3)

James Pasieka(3)

Keith Macdonald(1)(2)(4)

Murray Smith(1)(3)

Colin Davies(2)(4)

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee
(4) Member of the Environment, Health and Safety Committee

HEAD OFFICE

Address:
2100, 635 – 8th Avenue S.W.
Calgary, Alberta T2P 3M3

Phone: (403) 930-1010 Fax: (403) 930-1011
Email: invest@surgeenergy.ca
Website: www.surgeenergy.ca

ANNUAL GENERAL AND SPECIAL MEETING

Shareholders are cordially invited to attend the Annual General and Special Meeting of Surge Energy Inc., which will be held at 10:00 am Mountain Daylight Time on Thursday, June 16, 2011 in the Viking Room of the Calgary Petroleum Club (319 - 5 Avenue SW, Calgary, Alberta).

MANAGEMENT

Dan O'Neil
President, Chief Executive Officer and Director

Max Lof
Chief Financial Officer

Dan Brown
Chief Operating Officer

Malcolm Adams
Vice President Corporate Development

Margaret Elekes
Vice President Land

Kevin Angus
Vice President Exploration

Tee Ong
Vice President Engineering

LEGAL COUNSEL

Heenan Blaikie LLP, Calgary, Alberta

BANKER

National Bank of Canada, Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Olympia Trust Company, Calgary, Alberta

AUDITORS

KPMG LLP Chartered Accountants, Calgary, Alberta

INDEPENDENT ENGINEERS

Sproule Associates Limited, Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange (Venture) SGY

DESIGNED BY **Bryan Mills Iradesso**

ABBREVIATIONS

bcf	billion cubic feet
bbl	barrel
bbls/d	barrels per day
boe	barrel of oil equivalent on the basis of 1 boe to 6 mcf of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 mcf 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.
boe per day	barrels of oil equivalent per day
cagr	compound annual growth rate
km	kilometre
m	thousand
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf per day	thousand cubic feet per day
mcfe	thousand cubic feet equivalent
mm	million
mmbtu	million British Thermal Units
mmcf	million cubic feet

SURGE ENERGY INC
2100, 635 – 8th Avenue SW
Calgary, AB T2P 3M3
TSX-V: SGY