3 THIRD QUARTER REPORT

For the three months ended September 30, 2011

Sure Energy Inc. ("Sure Energy" or the "Company") is pleased to announce results for the third quarter 2011, ending September 30, 2011.

The Company's MD&A, Financial Statements and AIF can be viewed or downloaded at www.sureenergyinc.com or www.sedar.com.

During the third quarter of 2011, Sure Energy accomplished the following:

- Drilled 6 (5.8 net) successful oil wells at Redwater, Queensdale and Hatton during the third quarter of 2011
- Production averaged 1,057 BOE/d but with successful drilling in the third quarter production has now ramped up to 1,500 BOE/d (58% oil)
- In Virginia Hills the Company has successfully installed a liner and packer system into the 10-12-64-10 W5M Beaverhill Lake horizontal well and is set to perform an acid frac on the 100% well in November
- Funds flow from operations was $2.76 million or ($0.06 per share basis)
- The Company recently had its bank credit facility increased from $25 million to $33 million

	Three Months Ended September 30,		Nine Months Ended September 30,	
HIGHLIGHTS	**2011**	**2010**	**2011**	**2010**
($000 except share and per share amounts)				
Financial				
Petroleum and Natural Gas Revenues	4,972	2,012	16,457	7,250
Funds Flow from Operations (1)	2,759	582	8,709	2,738
Per Share, Basic and Diluted	0.06	0.01	0.18	0.06
Income (loss)	(293)	(533)	687	(647)
Per Share, Basic and Diluted	(0.01)	(0.01)	0.01	(0.01)
Capital Expenditures	9,987	3,962	30,162	8,244
Total Assets			77,941	43,350
Net Debt(1)			(36,342)	(10,228)
Shareholders' Equity			34,412	29,384
Common Shares Outstanding				
Basic			48,548,630	46,849,464
Diluted			52,644,464	51,154,464
Fully Diluted with Performance Rights and Warrants			57,974,464	54,659,464
Weighted Average Common Shares Outstanding				
Basic and Diluted	48,548,630	46,849,464	46,849,464	46,848,678
Share Trading				
High	1.79	1.32	1.99	1.37
Low	1.20	0.67	1.20	0.57
Close	1.30	1.34	1.30	1.34
Trading Volume	2,426,866	5,527,047	9,911,582	12,268,409

HIGHLIGHTS	**Three Months Ended September 30 2011**	**2010**	**Nine Months Ended September 30, 2011**	**2010**
Operations				
Production				
Natural Gas (Mcf/d)	3,523	3,972	3,712	4,307
Oil (bbls/d)	421	64	460	68
NGLs (bbls/d)	49	36	48	40
BOE/d	1,057	762	1,127	825
Average Selling Price				
Natural Gas ($/Mcf)	3.83	3.73	4.05	4.40
Oil ($/bbl)	88.78	80.05	91.22	77.45
NGLs ($/bbl)	65.15	53.33	68.31	59.57
BOE ($/BOE)	51.14	28.68	53.50	32.17
Operating Netback ($/BOE) [1]	31.85	13.05	34.42	16.76
Funds Flow Netback ($/BOE) [1]	28.38	8.28	28.30	12.15

(1) Please refer to Management's Discussion and Analysis for a definition of Non-GAAP measures.

OPERATIONAL REVIEW

Drilling

Capital expenditures for the period were as follows:

Capital Program Summary	**Three Months Ended September 30, 2011**	**2010**	**Nine Months Ended September 30, 2011**	**2010**
($000s)				
Land	332	27	1,435	729
Geological and geophysical	4	159	95	368
Drilling	4,260	2,508	6,408	4,212
Completions	3,387	273	4,563	856
Recompletions and workovers	624	22	934	816
Production equipment and facilities	1,453	853	4,289	1,304
Capitalized exploration G&A	185	52	556	161
Drilling credits	(115)	(1)	60	(451)
Asset acquisition (disposition)	(214)	14	11,138	155
Other assets	18	-	32	-
	9,934	3,907	29,510	8,150
Non-cash items				
Decommissioning obligations	645	55	1,244	94
Expiry of undeveloped land	(592)	-	(592)	-
	9,987	3,962	30,162	8,244

Drilling activity for the three and six months is summarized as follows:

Three Months Ended September 30, 2011

	Gas		**Oil**		**Dry and Abandoned**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration	-	-	-	-	-	-	-	-
Development	-	-	6	5.8	-	-	6	5.8
Total	-	-	6	5.8	-	-	6	5.8

Nine Months Ended September 30, 2011

	Gas		Oil		Dry and Abandoned		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration	-	-	-	-	-	-	-	-
Development	-	-	10	8.6	-	-	10	8.6
Total	-	-	10	8.6	-	-	10	8.6

Areas of Activity

Plains (Redwater)

The Company owns 11,095 net acres of land on the Lower Viking light oil trend at Redwater, just north of Edmonton. The Viking in the area has recently been exploited by horizontal drilling. Thirty day initial production rates typically vary from 60 – 125 barrels of oil per day, although some wells have averaged over 300 barrels of oil per day in the first 30 days. All of Sure Energy's horizontal wells are subject to the New Well Royalty Rate which reduces royalties to 5 percent for a defined period or production volume dependant on the length of the well. This royalty incentive leads to high operating netbacks. From its new wells in North Redwater, the first of which came on production in November 2010, Sure Energy has realized over $75 net operating income per BOE (income after royalties operating and transportation expenses).

In the third quarter of 2011 the Company produced 305 BOE/d from the Redwater (Plains) area of which 265 BOE/d was oil (87 percent). Oil production has significantly increased in the fourth quarter of 2011, as the Company has started to produce two new wells (one 100 percent and one 80 percent working interest), which were drilled in the third quarter and which are have added 244 net barrels of oil per day plus associated solution gas in October. The Company also has two 40 percent working interest wells on the south end of the productive trend which are awaiting tie-in.

Sure Energy has 42 gross (32 net) low risk development locations surrounded by or adjacent to production on the trend. In addition to this low risk drilling inventory the Company has 11.5 sections (11.0 net sections) of land still to evaluate on the productive oil trend.

SE Saskatchewan

Using a proprietary 3D seismic program Sure Energy identified an extension of the East Queensdale Alida light oil pool on its 100 percent working interest lands. In the third quarter of 2010 the Company drilled its first horizontal well into the interpreted extension. The well was an open hole drill and completion and cost just over $1.3 million to place on stream. The well came on production at over 200 barrels of oil per day and has paid out in just over three months. It benefited from the Saskatchewan horizontal well drilling incentive plan which reduces royalties to 2.5 percent for the first 6,000m^3 (37,740 barrels) of production. Production in the area is typified by increasing watercuts relatively early in the well's productive life. Despite the cost of managing the associated water production, the well realized an average netback of $67.59 per barrel for the third quarter of 2011. In the third quarter of 2011 the Company drilled three more horizontal wells into the prospect. All three wells were drilled from one surface site on which a facility will be constructed, which will include equipment to treat the oil and handle water for disposal. The wells all came on production during October.

In the third quarter of 2011 the Company produced 64 barrels of oil per day from southeast Saskatchewan, which was from the original Queensdale well. The three follow up wells are currently on production but are as yet not producing at optimal rates. Field estimates for October are 270 barrels of oil per day (100% oil) from the property.

Virginia Hills

In April of 2011 Sure Energy closed the second of two acquisitions in the Virginia Hills area thereby creating a new core area. The Company acquired 69 sections of land (average 64 percent working interest) of various mineral rights and 160 BOE/d of associated production (72 barrels of oil per day) for $11.1 million.

The initial motivation for establishing a position in the Virginia Hills area was to gain exposure to a Viking resource play, similar to Redwater.

The Viking section at Virginia Hills is approximately twice as thick as that at Redwater. The resource upside of the play exists in low permeabilty sediments. Two key vertical wells demonstrate that the Viking contains oil and will produce it when frac'd, albeit at marginally economic rates. The two key vertical producers produce at steady rates of 6 and 10 barrels of oil per day which compares to rates of two to five barrels of oil per day from mature vertical producers at Redwater. In theory a multiple fractured horizontal well should produce at a comparable multiple to the vertical wells in the Redwater area (i.e. two to three times better). No horizontals have been drilled in the Viking in the Virginia Hills area to date. The Company owns 9.5 sections with approximately 50 percent working interest and 3 sections with 100 percent working interest on the core area of the play. Sure Energy plans to drill one vertical well on its 100 percent lands and two horizontal wells on its 50 percent working interest lands late in 2011 or early in 2012.

Through the acquisitions the Company also acquired 1,705 acres (2.7 net sections) of land with Beaverhill Lake rights. Horizontal wells drilled into the Beaverhill Lake and frac'd multiple times with large volumes of acid have exhibited high production rates. Included in Sure Energy's acquisition at Virginia Hills were two horizontal Beaverhill Lake producers which were completed open hole but were never frac'd. Both wells produce clean oil, but at low rates (15- 22 barrels per day) consistent with production from a low permeability reservoir. Both these wells should exhibit markedly higher production rates if frac'd in a similar way to prolific offset producers. To this end the Company has installed a liner and packer system in its 10-12-64-10 horizontal wellbore and has set the well up to be acid frac'd. The Company is currently securing the acid and the services to frac this wellbore as soon as possible. This operation will cost the Company approximately $2 million as opposed to the $5 to 6 million required to drill and complete a new well. Should the operation prove successful the Company will attempt a similar completion on its unfrac'd wellbore in 10-23-65-13 W5M.

Hatton (SW Saskatchewan)

In September 2011 Sure Energy drilled its first well into a heavy oil prospect at Hatton in southwest Saskatchewan. The Company's vertical appraisal well encountered 6.5 meters of heavy oil pay. The well was completed and is currently awaiting facility construction and the installation of a screw pump to enable it to be placed on production. The well is expected to commence production in mid November. Encouraged by the well's results the Company purchased three additional sections of 100 percent working interest lands (to give it a total of 4) on the play.

Other Properties

The Company produces approximately 500- 550 BOE/d from the Peace River Arch, Southern Plains (Chinook), Tweedie and a series of minor properties in the West Central area of Alberta. Most of this production is gas and due to the current depressed state of the gas markets the Company has spent very little capital in 2011 on these properties. Furthermore the Company has no immediate plans to expose significant capital in these areas.

Production

Production for the period by major property is as follows:

	Three Months Ended September 30, 2011			
	Gas Mcf/d	**Oil Bbls/d**	**NGLs Bbls/d**	**Total BOE/d**
Peace River	915	10	16	179
Plains	238	265	-	305
Saskatchewan	-	64	-	64
Southern Plains	536	-	2	92
Tweedie	819	-	-	137
West Central	1,015	82	31	280
Total	3,523	421	49	1,057

	Nine Months Ended September 30, 2011			
	Gas Mcf/d	**Oil Bbls/d**	**NGLs Bbls/d**	**Total BOE/d**
Peace River	1,025	11	16	198
Plains	298	327	-	377

Saskatchewan	-	64	-	64
Southern Plains	805	-	5	139
Tweedie	777	-	-	130
West Central	807	58	27	219
Total	3,712	460	48	1,127

Production for the period was 1,057 BOE/d, essentially flat to that of the second quarter. Production volumes for the period were particularly impacted by gas plant dew point problems at a third party plant in Southern Plains, which reduced volumes by 60 BOE/d and by high line pressures in the Hill and Gordondale areas of the Peace River Arch which impacted overall capability by 41 BOE/d. In the Redwater area the 12-2-58-23 well was shut in for most of July due to wet weather trucking issues and this impacted volumes for the period by approximately 20 BOE/d. In the Virginia Hills area oil trucking interruptions on one of the Company's Gething oil wells contributed to reducing volumes by approximately 20 BOE/d.

The Company is currently producing approximately 1,500 BOE/d (about 60 percent oil and liquids) according to field estimates. Some minor volumes of gas have been shut-in at Chinook (approximately 30 BOE/d) for economic reasons and about 40 BOE/d of gas at Gordondale flows only intermittently because of high line pressures. The Company is also waiting for its two 40 percent wells at south Redwater to be tied in and expects its new Hatton heavy oil well to come on production in mid November.

OUTLOOK

After a very busy operational final quarter of 2010 the Company was less active drilling in first half of 2011. During this period the focus was on extending the Company's portfolio of opportunities to sustain future growth. This was achieved by the acquisition of the Virginia Hills property which has exposed the Company to another resource play in the Viking formation and a high impact play in the Beaverhill Lake. The Company is set to acid frac one of its Beaverhill Lake wells in the Virginia Hills area as soon as services become available. The Viking in the area has never been exploited by multi-frac'd horizontal wells. The reservoir section is thicker than at Redwater. Drilling horizontal wells and multi-frac'ing technology should greatly improve productivity as it does at Redwater. Success with this prospect would layer on another wedge of resource development locations to the Company's drilling inventory.

Significant potential exists with Sure Energy's Hatton prospect. Test results on the initial well are extremely encouraging. The Company is currently installing facilities to establish productivity. The next step is to determine the extent of the pool with two or three delineation wells. When this is complete the Company will be able to evaluate the potential of the resource and its economic impact.

Redwater has become the cornerstone of the Company. The economics of the play are compelling. The Company brought on six new wells at North Redwater between November 2010 and February 2011. Those six wells cost an average of $1.75 million each to drill, case, complete and equip. Another $1.47 million was spent on the project for multi-well pad construction, roads, pipelines, and workovers for a total of $12 million. By the end of September the wells had been on production for 53 months collectively and had produced 94,634 barrels of oil generating net operating income of $7.2 million (income after royalties, operating expenses and transportation). In September the wells generated net operating income of $0.5 million. This was the Company's first major capital exposure to the play; success and repeatability were of utmost importance. As the Company moves forward with development, costs and operating efficiencies will improve, and the economics will improve even more. The Company has an extensive (minimum 32 net) low risk development inventory on the play and 11 ½ more sections to evaluate.

The Company has taken steps to improve its operating efficiencies and ability to execute its drilling and completion plans. As drilling and completion services become more difficult and expensive to attain it is extremely important that drilling programs be planned well in advance. Recognizing this the Company has added a Drilling and Completions Manager to its staff.

In the third quarter of 2010 Sure Energy produced 762 BOE/d of which 64 barrels per day was oil. In October 2011 the Company estimates production of approximately 1,500 BOE/d of which 870 barrels per day is oil. This represents a significant turnaround for the Company in the past year. The Company has the development locations to continually add to the oil production base plus has three projects which could significantly enhance the oil drilling inventory.

With an increased credit facility along with the undrawn portion of the Deans Knight Debenture the Company continues to have financial flexibility with over $16.7 million of available credit capacity.

MANAGEMENT'S DISCUSSION AND ANALYSIS

November 8, 2011

This management's discussion and analysis ("MD&A") for Sure Energy Inc. ("Sure Energy" or the "Company") should be read in conjunction with the audited financial statements of the Company as at December 31, 2010 and 2009 together with the accompanying notes. Additional information relating to the Company can be viewed or downloaded at www.sureenergyinc.com or www.sedar.com. Readers should also read the "Forward Looking Information" legal advisory contained at the end of this MD&A.

Management is responsible for preparing the MD&A. The Audit Committee of the Sure Energy Board of Directors (the "Board") reviewed the MD&A and recommended its approval by the Board.

This MD&A and the interim Financial Statements for the nine months ended September 30, 2011 and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS"), which are also generally accepted accounting principles ("GAAP"). For all periods up to and including the year ended December 31, 2010, the Financial Statements were prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). In accordance with the standard related to the first time adoption of IFRS, the transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following Canadian GAAP and as allowed by the standard related to the first time adoption of IFRS ("IFRS 1"), has not been represented on an IFRS basis.

Throughout the report BOE, or barrel of oil equivalent, is defined as 6 Mcf to 1 bbl. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

BUSINESS AND FINANCIAL STRATEGY

Sure Energy is a junior oil and gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves primarily in Alberta and Saskatchewan. Sure Energy's main objective is value creation by providing a shareholder exposure to emerging development plays with large volumes of oil and gas in place, such as the conventional Viking light oil development at Redwater, and exposure to higher impact exploration targets. Sure Energy achieves its objective through a combination of exploration activities, drilling and assessing strategic acquisitions.

OVERVIEW
Selected Annual and Quarterly Information

	Q3 11	Q2 11	Q1 11	2010	Q4 10	Q3 10	Q2 10	Q1 10	2009	Q4 09
Production										
Natural gas (Mcf/d)	3,523	3,823	3,794	**4,248**	4,071	3,972	3,982	4,978	**3,532**	3,614
Oil (bbls/d)	421	378	584	**196**	578	64	68	72	**42**	66
NGLs (bbls/d)	49	45	50	**40**	41	36	39	44	**31**	39
BOE/d	1,057	1,060	1,266	**944**	1,297	762	771	945	**662**	708
Average Selling Price										
Natural gas ($/Mcf)	3.83	4.11	4.19	**4.26**	3.82	3.73	4.11	5.17	**4.07**	4.69
Oil ($/bbl)	88.78	101.49	86.30	**78.11**	78.34	80.05	74.47	77.92	**65.87**	73.73
NGLs ($/bbl)	65.15	73.31	66.93	**59.01**	57.38	53.33	60.67	63.89	**44.66**	50.98
$/BOE	51.14	54.10	55.00	**37.90**	48.70	28.68	30.88	36.11	**28.02**	33.66
Netback ($/BOE)										
Operating	31.85	32.64	38.15	**22.86**	34.36	13.05	18.17	18.65	**12.89**	16.61
Funds Flow	28.38	26.78	29.55	**19.59**	30.75	8.28	13.32	14.37	**7.31**	10.33

Financial
($000s except share and per share amounts)

	Q3 11	Q2 11	Q1 11	2010	Q4 10	Q3 10	Q2 10	Q1 10	2009	Q4 09
Revenue	4,972	5,217	6,268	13,063	5,813	2,012	2,165	3,073	6,765	2,193
Funds Flow	2,759	2,581	3,369	6,407	3,671	582	936	1,220	1,766	672
Per share, basic	0.06	0.05	0.07	0.13	0.08	0.01	0.02	0.03	0.04	0.01
Income (loss)	(293)	435	545	(532)	116	(533)	(228)	114	(3,760)	(828)
Per share, basic	(0.01)	0.01	0.01	(0.01)	0.00	(0.01)	(0.00)	0.00	(0.09)	(0.02)
Capital Expenditures	9,987	10,222	9,953	17,613	9,370	3,962	2,042	2,240	11,398	1,631
Total Assets	77,941	68,969	61,499		53,685	43,350	40,064	39,463		37,908
Net Debt	(36,342)	(28,848)	(21,214)		(14,700)	(10,228)	(6,797)	(5,594)		(4,537)
Shareholder's Equity	34,412	34,549	34,075		33,230	29,384	29,752	29,808		30,054
Common Shares (000's)	48,549	48,549	48,529		48,431	46,849	46,849	46,849		46,874

Q3 2011
Production was consistent with the previous quarter. Capital expenditures during the period included the drilling of 6 gross (5.8 net) wells. These wells will commence production in the fourth quarter of 2011.

Q2 2011
Revenue decreased during the quarter as a result of a decrease in oil production at Redwater and Queensdale. Breakup and flooding in Saskatchewan caused production to be shut in. During the quarter the Company closed an asset acquisition in Virginia Hills for $7.6 million.

Q1 2011
Revenue increased in the quarter due to increases in the price of oil. During the quarter, a bonus of $546,000 was paid to employees. Capital expenditures included an asset acquisition for $3.7 million.

Q4 2010
Revenue increased significantly during the quarter due to new oil production at Redwater and Saskatchewan. Capital expenditures reflected 5 gross (5.0 net) wells drilled at Redwater in the quarter. Sure Energy entered into a $20 million term loan facility. $10 million was drawn during the quarter.

Q3 2010
Revenue decreased slightly during the quarter as a result of a decrease in commodity prices and production declines. Capital expenditures included successful oil wells drilled in Redwater and Saskatchewan. These wells commenced production in the fourth quarter of 2010.

Q2 2010
Revenue decreased during the quarter as a result of a decrease in commodity prices and reduced gas production. Production from the Peace River Arch and in Chinook was temporarily restricted due to voluntary gas plant turnarounds by the operator. The Company received a gas cost allowance credit of $183,000 during the quarter which reduced royalty expense.

Q1 2010
Revenue increased during the quarter from increases in oil and gas prices and increased gas production from the Peace River Arch well that commenced production in January 2010. Capital expenditures included 4 gross (2.8 net) wells that were drilled in the quarter.

Q4 2009
Revenue increased during the quarter mainly due to a recovery in the price of natural gas. Capital expenditures included a well that was drilled, completed and tied-in on the Peace River Arch. The well commenced production on January 1, 2010.

RESULTS OF OPERATIONS

Revenues	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
Petroleum and Natural Gas Revenue ($000s)	**2011**	**2010**	**2011**	**2010**
Natural gas	1,242	1,362	4,102	5,169
Oil	3,437	471	11,459	1,434
NGLs	293	179	896	647
	4,972	2,012	16,457	7,250

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
Production	**2011**	**2010**	**2011**	**2010**
Natural gas (Mcf/d)	3,523	3,972	3,712	4,307
Oil (bbls/d)	421	64	460	68
NGLs (bbls/d)	49	36	48	40
BOE/d	1,057	762	1,127	825

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
Average Selling Price	**2011**	**2010**	**2011**	**2010**
Natural gas ($/Mcf)	3.83	3.73	4.05	4.40
Oil ($/bbl)	88.78	80.05	91.22	77.45
NGLs ($/bbl)	65.15	53.33	68.31	59.57
$/BOE	51.14	28.68	53.50	32.17

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
Average Benchmark Prices	**2011**	**2010**	**2011**	**2010**
AECO (daily) natural gas ($/Mcf)	3.47	3.36	3.57	3.91
WTI Crude oil (US$/bbl)	89.76	76.20	95.48	77.65
Edmonton par price (Cdn $/bbl)	91.78	74.46	94.31	76.60
Exchange rate (US$/Cdn$)	0.9802	1.0391	0.9780	1.0359

Revenue for the quarter was $5.0 million versus $2.0 million for the comparative quarter. Production for the quarter averaged 1,057 BOE/d, representing an increase of 39 percent over the comparative quarter. The Company's realized price for its natural gas was $3.83/Mcf for the quarter. The Company received an average price for its oil sales for the quarter of $88.78/bbl (Q3 2010 - $80.05/bbl).

Revenue for the nine months was $16.5 million versus $7.3 million for the comparative period. Production for the nine months averaged 1,127 BOE/d, representing an increase of 37 percent over the comparative quarter. The Company's realized price for its natural gas was $4.05/Mcf for the nine months, 8 percent less than the $4.40/Mcf received in the comparative period. The Company received an average price for the nine months of $91.22/bbl (Q3 2010 YTD - $77.45/bbl).

Production in the current periods included oil from horizontal wells drilled at Redwater and Saskatchewan which increased production and average selling price per BOE.

The Company has not hedged or entered into any fixed price arrangements during 2011 or for any subsequent period.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2011**	**2010**	**2011**	**2010**
Royalties	540	175	1,740	758
Average royalty as a percent of revenue	10.9	8.7	10.6	10.5

Royalties as a percentage of revenue increased to 10.9 percent for the third quarter versus 8.7 percent for the comparative quarter. Royalties as a percentage of revenue decreased to 10.6 percent for the nine months versus 10.5 percent for the comparative period. The Company received gas cost allowance credits based on capital spent by Sure Energy in prior periods. Gas royalty rates increased due to the expiry of incentives on new production. New oil production at Redwater qualifies for a royalty of five percent for the first 24 months and new oil production in Saskatchewan qualifies for a royalty of 2.5 percent for the first 6,000 cubic metres.

Operating expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2011**	**2010**	**2011**	**2010**
Operating expenses	1,034	807	3,281	2,330

Operating costs were $1.0 million or $10.63 per BOE for the third quarter versus $0.8 million or $11.51 per BOE for the comparative period. Operating costs were $3.3 million or $10.67 per BOE for the nine months versus $2.3 million or $10.34 per BOE for the comparative period. Operating costs for the current quarter decreased by $1.69/BOE due to a one time processing fee adjustment.

Operating costs per barrel are generally higher for oil than gas. There was a higher proportion of oil produced in the current versus comparative period.

Transportation

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2011**	**2010**	**2011**	**2010**
Transportation	302	114	845	385

Transportation costs were $3.10 per BOE in the third quarter and $1.62 per BOE for the comparative period. Transportation costs were $2.75 per BOE in the nine months and $1.71 per BOE for the comparative period. Transportation costs relate to the costs of transporting Sure Energy's natural gas production on major pipelines and trucking Sure Energy's oil to the point of transfer. Transportation costs increased in the current period due to the higher trucking costs on the increased oil production.

Exploration and Evaluation	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
($000s)	**2011**	**2010**	**2011**	**2010**
	632	40	715	135

For the three and nine months ended September 30, 2011, exploration and evaluation expenses include $592,000 of costs related to expiring leases.

General and Administrative	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
($000s)	**2011**	**2010**	**2011**	**2010**
Gross general and administrative	522	386	2,438	1,200
Capitalized overhead	(185)	(52)	(556)	(161)
	337	334	1,882	1,039

General and administrative (“G&A”) costs were $3.47 per BOE for the third quarter and $4.77 per BOE for the comparative period. G&A costs were $6.12 per BOE for the nine months and $4.61 per BOE for the comparative period. Bonuses of $546,000 were paid to employees of the Company in the nine months ended September 30, 2011. G&A costs will decrease on a per BOE basis as the Company grows its production. As activity increases, the Company will apply overhead charges, which are charged to specific well operations, and reduce G&A as is customary in the industry.

Interest and financing charges	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
($000s)	**2011**	**2010**	**2011**	**2010**
Interest	278	66	853	148
Financing charges	268	24	605	45
	546	90	1,458	193

The interest rate was 4.00 percent on the bank debt and 6.25 percent on the note facility.

Financing charges include amortization of deferred financing costs of the note facility and accretion of decommissioning obligations. Accretion of the decommissioning obligations is calculated at the Company’s credit-adjusted, risk-free rate of 4 percent. The Company has estimated the net present value of the decommissioning obligations to be $3.1 million.

Depletion, Depreciation and Amortization

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($000s)	**2011**	**2010**	**2011**	**2010**
Depletion and depreciation	1,717	819	5,489	2,664

The Company’s depletion, depreciation and amortization (“DD&A”) provision for the third quarter was $1.7 million, or $17.66 per BOE and $0.8 million or $11.68 per BOE for the comparative period. The Company’s DD&A provision for the nine months was $5.5 million or $17.84 per BOE and $2.7 million or $11.82 per BOE for the comparative period. DD&A per BOE increased due to increased production in Redwater.

Stock Based Compensation

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($000s)	**2011**	**2010**	**2011**	**2010**
Stock compensation	157	166	360	393

Stock based compensation expense was $157,000 in the third quarter and $166,000 for the comparative period.

Income and deferred taxes
The Company does not expect to pay current income tax in 2011 or 2012. Estimated income tax pools at September 30, 2011 are as follows:

($000s)	
Canadian oil and gas property expenses	19,314
Canadian development expenses	14,593
Canadian exploration expenses	7,575
Undepreciated capital costs	11,437
Non-capital losses	28,366
Financing costs	136
Successored pools (restricted)	16,244
	97,665

Netbacks
Components of the Company's operating, funds flow and netbacks are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	2011	2010	2011	2010
Price	51.14	28.68	53.50	32.17
Royalties	(5.56)	(2.50)	(5.66)	(3.36)
Operating costs	(10.63)	(11.51)	(10.67)	(10.34)
Transportation	(3.10)	(1.62)	(2.75)	(1.71)
Operating Netback	31.85	13.05	34.42	16.76
General and administrative	(3.47)	(4.77)	(6.12)	(4.61)
Funds Flow Netback	28.38	8.28	28.30	12.15
Exploration and evaluation	(6.50)	(0.57)	(2.33)	(0.60)
Interest and financing charges	(5.62)	(1.29)	(4.74)	(0.86)
Depletion, depreciation and amortization	(17.66)	(11.68)	(17.84)	(11.82)
Stock compensation	(1.61)	(2.36)	(1.17)	(1.74)
Netback	(3.01)	(7.62)	2.22	(2.87)

CAPITAL EXPENDITURES

Capital expenditures for the period were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Capital Program Summary	**2011**	**2010**	**2011**	**2010**
($000s)				
Land	332	27	1,435	729
Geological and geophysical	4	159	95	368
Drilling	4,260	2,508	6,408	4,212
Completions	3,387	273	4,563	856
Recompletions and workovers	624	22	934	816
Production equipment and facilities	1,453	853	4,289	1,304
Capitalized exploration G&A	185	52	556	161
Drilling credits	(115)	(1)	60	(451)
Asset acquisition (disposition)	(214)	14	11,138	155
Other assets	18	-	32	-
	9,934	3,907	29,510	8,150
Non-cash items				
Decommissioning obligations	645	55	1,244	94
Expiry of undeveloped land	(592)	-	(592)	-
	9,987	3,962	30,162	8,244

Drilling activity for the three and six months is summarized as follows:

Three Months Ended September 30, 2011

	Gas		Oil		Dry and Abandoned		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration	-	-	-	-	-	-	-	-
Development	-	-	6	5.8	-	-	6	5.8
Total	-	-	6	5.8	-	-	6	5.8

Nine Months Ended September 30, 2011

	Gas		Oil		Dry and Abandoned		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration	-	-	-	-	-	-	-	-
Development	-	-	10	8.6	-	-	10	8.6
Total	-	-	10	8.6	-	-	10	8.6

Capital expenditures for the nine months include two Virginia Hills asset acquisitions for $11.1 million.

SHARE CAPITAL

The following common shares, options, performance incentive rights and warrants were outstanding:

Outstanding at:	September 30, 2011	December 31, 2010	November 8, 2011
Common shares	48,548,630	48,431,130	48,548,630
Options	4,095,834	3,793,334	4,335,834
Performance incentive rights	2,830,000	2,880,000	2,830,000
Warrants	2,500,000	2,500,000	2,500,000
	57,974,464	57,604,464	58,214,464

During the nine months ended September 30, 2011, 117,500 shares were issued upon the exercise of options and performance incentive rights.

On May 25, 2011, Sure Energy extended the term of certain options from five to seven years. The options extended were 1,385,000 stock options granted on August 22, 2006 at an exercise price of 1.28, 530,334 stock options granted on November 7, 2008 at an exercise price of $0.39 and 1,158,000 stock options granted on May 14, 2010 at an exercise price of $0.98. The terms were changed so that all of the Company’s options have a term of seven years. All of the options were in the money as of May 25, 2011. There was no impact on the accounting for the stock options as all stock options, which now have a seven year life, are valued having an expected life of five years.

CAPITALIZATION, FINANCIAL RESOURCES AND LIQUIDITY

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence, and to sustain future investing in oil and gas activities which may or may not be successful. The objective is to balance the proportion of debt and equity in its capital structure. The Company defines its capital structure to include shareholders' equity, bank debt, the note facility and working capital. The key measures that the Company utilizes in evaluating its capital structure are net debt to funds flow from operations, net debt as a percent of total capitalization and the current credit available from its creditors in relation to the Company's budgeted capital program. Funds flow from operations is a non-GAAP measure and it is used by the Company to analyze operating performance, leverage and liquidity. The Company's capitalization and calculation of funds flow from operations is as follows:

	September 30, 2011	December 31, 2010
Net debt		
Working capital		
Trade and other receivables	(2,775)	(3,110)
Deposits and prepaid expenses	(1,308)	(853)
Trade and other payables	9,884	8,223
	5,801	4,260
Note facility	10,000	10,000
Bank debt	20,541	440
Total net debt	36,342	14,700
Market capitalization		
Common shares outstanding	48,548,630	48,431,130
Closing price, TSX	1.30	1.75
Total market capitalization	63,113	84,754
Total net debt and market capitalization	99,445	99,454
Net debt as a percent of total capitalization	37%	15%

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
Funds flow from operations:			
Net income (loss) for the period	(293)	687	(532)
Adjustments:			
Exploration and evaluation expenditures	632	715	602
Depletion, depreciation and amortization	1,717	5,489	4,860
Impairment	-	-	423
Interest and financing charges	546	1,458	344
Stock based compensation	157	360	710
Total funds flow from operations	2,759	8,709	6,407
Trailing 12 months funds flow from operations		12,380	6,407
Net debt to trailing 12 months funds flow from operations ratio		2.94	2.29

The Company also assesses its capital structure by forecasting cash flows and estimated debt levels. There are several strategies to maintain or adjust capital structure including increasing bank credit as a result of reserve growth, decreasing capital spending and new equity issues.

The Company is subject to a covenant on its bank credit facility to maintain its ratio of current assets (including the undrawn portion of the credit facilities) to current liabilities (not including current bank debt) at a 1.0:1.0 level. As at September 30, 2011, the ratio was 1.88 (December 31, 2010 - 2.25).

At September 30, 2011, Sure Energy had total credit facilities of $45.0 million, consisting of a $25 million bank credit facility and a $20 million Secured Note Facility. At September 30, 2011, $30.5 million was drawn on the credit facilities.

On November 8, 2011 the bank credit facility was increased to $33 million increasing total credit facilities to $53 million.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

Canadian GAAP for publicly accountable enterprises was replaced by IFRS for fiscal years beginning on or after January 1, 2011. Companies are required to provide IFRS comparative information for the previous fiscal year. Accordingly, the conversion from Canadian GAAP to IFRS was applicable to reporting for the first quarter of 2010, for which the current and comparative information was prepared under IFRS.

The transition process to IFRS consisted of the following phases:

- Scoping – Management completed a comprehensive analysis of its financial statements to identify areas that may be impacted by transitioning to IFRS.
- Impact Analysis – Management developed IFRS policies and assessed the impact of these policies on Sure Energy. The Audit Committee reviewed and approved all IFRS policies proposed by management.
- Implementation - The policies were implemented and changes were made to the financial statements, the accounting process and any other business processes that may be affected.

The following is a summary of the impact of IFRS on the Company:

(a) IFRS 1 exemptions
IFRS was applied retrospectively at the transition date with all adjustments to assets and liabilities as stated under Canadian GAAP taken to retained earnings unless certain exceptions and exemptions are applied.
IFRS 1, “First-Time Adoption of International Financial Reporting Standards”, permitted first time adopters of IFRS a number of exemptions. The Company elected to utilize the following exemptions for first-time adoption of IFRS:
   (i) IFRS 1, First-Time Adoption of International Financial Reporting Standards, whereby the petroleum asset balance as determined under Canadian GAAP was allocated to the IFRS categories of exploration and evaluation assets and PP&E. Under the exemption, for assets in the development or production phases, the amount was allocated to the underlying IFRS transitional assets on a pro-rata basis using proved and probable reserve values as of the IFRS transition date. This resulted in a $1.9 million increase in exploration and evaluation assets with a corresponding decrease in PP&E.
   (ii) IFRS 3, Business Combinations, which allows for an implementation of the IFRS business combination rules on a prospective basis, therefore, business combinations entered into prior to January 1, 2010 were not retrospectively restated;
   (iii) IFRS 2, Share-based payments, whereby stock options that vested prior to January 1, 2010 are not required to be retrospectively restated. Therefore, IFRS requirements apply only to those options that were unvested at the date of transition;
   (iv) IFRS 23, Borrowing Costs, whereby borrowing cost disclosures relating to qualifying assets are applied prospectively from the IFRS transition date.

(b) Decommissioning obligations:
Under Canadian GAAP, decommissioning obligations were discounted at a credit adjusted risk free rate of 8 percent. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted, therefore, the provision is discounted at a risk free rate of 4 percent. Upon transition to IFRS, this resulted in a $0.4 million increase in the decommissioning obligations with a corresponding decrease in retained earnings.
Under Canadian GAAP, accretion of the discount was included in depletion and depreciation. Under IFRS it is included in interest and financing charges. Under Canadian GAAP, expenditures on remediation and abandonment were not included in changes in non-cash working capital as done under IFRS.

(c) Flow-through shares:
For Canadian GAAP, equity is reduced for the value of the tax pools renounced to flow-through shareholders. Under IFRS, equity is reduced by the premium paid for the flow-through share versus a normal share. The Company issued 1.9 million flow-through shares in 2008. Share capital is approximately $0.3 million less under IFRS than Canadian GAAP for this difference, with a corresponding increase to retained earnings.

(d) Depletion policy:
Upon transition to IFRS, the Company adopted a policy of depleting PP&E on a unit of production basis over proved and probable reserves. The depletion policy under Canadian GAAP was based on units of

production over proved reserves. In addition, depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (ie. fields or combinations thereof).
There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed above.
For the year ended December 31, 2010, this resulted in a decrease to depletion of $3.3 million (nine months ended September 30, 2010 - $2.6 million) with a corresponding change to PP&E. An impairment of $0.4 million was also recorded for the year ended December 31, 2010.

(e) Directly attributable salaries and benefits:
Certain salaries and benefits were capitalized under Canadian GAAP and not under IFRS. For the year ended December 31, 2010, this resulted in an increase in general and administrative expenses of $143,000 (nine months ended September 30, 2010 - $115,000) and a corresponding decrease in PP&E.

(f) Statement of cash flows:
Under Canadian GAAP, interest paid was classified as operating. Under IFRS, interest paid was classified as financing. For the year ended December 31, 2010 this resulted in an increase in net cash from operating activities of $251,000 (nine months ended September 30, 2010 - $148,000) and a corresponding decrease to cash flows from financing activities.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures are designed to provide reasonable assurance that material information is gathered and reported to senior management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to permit timely decisions regarding public disclosure.

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). ICFR is a process designed by or under the supervision of the Chief Executive Officer and Chief Financial Officer, and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Management has completed an assessment of the design of ICFR. The Company used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework and guidance for smaller public companies for the design of the Company's ICFR. All internal control systems have inherent limitations and therefore our ICFR can only provide reasonable assurance and may not prevent or detect misstatements due to error or fraud.

The Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation of the design and operating effectiveness of the Company's disclosure controls and ICFR as of the date of this MD&A, that disclosure controls and ICFR are not effective due to the material weakness in ICFR as described below. The material weakness identified did not result in any adjustments to the Company's financial statements for the three months ended September 30, 2011 or any prior period.

During the process of management's assessment, it was determined that a deficiency existed in the ICFR. Segregation of duties was identified as an area where a deficiency exists. Specifically, certain duties within the accounting department were not segregated due to the limited number of individuals employed in this area. The risk of a material misstatement is mitigated by direct involvement of senior management in the day to day operations of the Company and review of the financial statements and disclosures by senior management and the Board of Directors. However, these mitigating procedures are not considered sufficient to reduce the likelihood that a material misstatement would be prevented or detected. This weakness and its related risks is not uncommon in an entity of the size of the Company. As the Company grows, it plans to expand the number of individuals involved in the accounting function.

There have been no significant changes in the Company's ICFR that occurred during the period ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

OUTLOOK

After a very busy operational final quarter of 2010 the Company was less active drilling in first half of 2011. During this period the focus was on extending the Company's portfolio of opportunities to sustain future growth. This was achieved by the acquisition of the Virginia Hills property which has exposed the Company to another resource play in the Viking formation and a high impact play in the Beaverhill Lake. The Company is set to acid frac one of its Beaverhill Lake wells in the Virginia Hills area as soon as services become available. The Viking in the area has never been exploited by multi-frac'd horizontal wells. The reservoir section is thicker than at Redwater. Drilling horizontal wells and multi-frac'ing technology should greatly improve productivity as it does at Redwater. Success with this prospect would layer on another wedge of resource development locations to the Company's drilling inventory.

Significant potential exists with Sure Energy's Hatton prospect. Test results on the initial well are extremely encouraging. The Company is currently installing facilities to establish productivity. The next step is to determine the extent of the pool with two or three delineation wells. When this is complete the Company will be able to evaluate the potential of the resource and its economic impact.

Redwater has become the cornerstone of the Company. The economics of the play are compelling. The Company brought on six new wells at North Redwater between November 2010 and February 2011. Those six wells cost an average of $1.75 million each to drill, case, complete and equip. Another $1.47 million was spent on the project for multi-well pad construction, roads, pipelines, and workovers for a total of $12 million. By the end of September the wells had been on production for 53 months collectively and had produced 94,634 barrels of oil generating net operating income of $7.2 million (income after royalties, operating expenses and transportation). In September the wells generated net operating income of $0.5 million. This was the Company's first major capital exposure to the play; success and repeatability were of utmost importance. As the Company moves forward with development, costs and operating efficiencies will improve, and the economics will improve even more. The Company has an extensive (minimum 32 net) low risk development inventory on the play and 11 ½ more sections to evaluate.

The Company has taken steps to improve its operating efficiencies and ability to execute its drilling and completion plans. As drilling and completion services become more difficult and expensive to attain it is extremely important that drilling programs be planned well in advance. Recognizing this the Company has added a Drilling and Completions Manager to its staff.

In the third quarter of 2010 Sure Energy produced 762 BOE/d of which 64 barrels per day was oil. In October 2011 the Company estimates production of approximately 1,500 BOE/d of which 870 barrels per day is oil. This represents a significant turnaround for the Company in the past year. The Company has the development locations to continually add to the oil production base plus has three projects which could significantly enhance the oil drilling inventory.

With an increased credit facility along with the undrawn portion of the Deans Knight Debenture the Company continues to have financial flexibility with over $16.7 million of available credit capacity.

Non-GAAP Measures

Sure Energy management uses and reports certain non-GAAP measures in the evaluation of operating and financial performance. These measures do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other companies. Funds flow from operations, operating and cash flow netbacks, net debt and working capital are metrics used to compare Sure Energy with its peers.

Funds flow from operations is used by the Company to analyze operating performance, leverage and liquidity. Readers should refer to the "CAPITALIZATION, FINANCIAL RESOURCES AND LIQUIDITY" section of the MD&A for a reconciliation of funds flow from operations.

We use the terms Operating Netbacks and Cash Flow Netbacks to evaluate operational performance of the Company. Operating netback, which is calculated as average unit sales price less royalties, transportation costs and operating expenses and cash flow netback, which further deducts administrative and interest expense and current income tax represents the cash margin for every barrel of oil equivalent sold. Readers should refer to the "Netbacks" section of the MD&A for the calculations of operating and cash flow netbacks.

Net debt and working capital, which is current assets less debt and current liabilities, is used to assess efficiency and financial strength. Readers should refer to the "LIQUIDITY AND CAPITAL RESOURCES" section of the MD&A for a reconciliation of net debt and working capital.

Forward-looking Information

Certain statements contained in this management's discussion and analysis constitute forward-looking information. These statements relate to future events or Sure Energy's future performance. The use of any of the words "could", "expect", "believe", "will", "projected", "estimated" and similar expressions and statements relating to matters that are not historical facts are intended to identify forward-looking information and are based on Sure Energy's current belief or assumptions as to the outcome and timing of such future events. Actual future results may differ materially. In particular, the statements related to commencement of production of the six wells drilled in the third quarter, expectations with respect to general and administrative costs, expectations for the payment of current income tax, and in the section "Outlook" are forward looking information. Sure Energy's Annual Information Form and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com) describe the risks, material assumptions and other factors that could influence actual results and which are incorporated herein by reference. Sure disclaims any intention or obligation to publicly update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as may be expressly required by applicable securities laws.

GLOSSARY OF ABBREVIATIONS

$000s	Thousands of dollars	Mbbls	Thousands of barrels
AECO	Alberta Energy Co.	MBOE	Thousand barrels of oil equivalent
AEUB	Alberta Energy Utilities Board	Mcf	Thousand cubic feet
bbls	Barrels	Mcf/d	Thousand cubic feet per day
bbls/d	Barrels per day	MMcf	Million cubic feet
Bcf	Billion cubic feet	MMcf/d	Million cubic feet per day
BOE	Barrel of oil equivalent (6 Mcf = 1 bbl)	MMbtu	Millions of British thermal units
BOE/d	Barrels of oil equivalent per day	NGLs	Natural gas liquids
GJ	Gigajoules	NPV	Net present value
G&A	General and administrative	TSX	Toronto Stock Exchange

SURE ENERGY INC.

Condensed Statement of Financial Position

(in thousands of Canadian dollars)
(unaudited)

	Note	September 30, 2011	December 31, 2010 (note 12)	January 1, 2010 (note 12)
Assets				
Trade and other receivables		$ 2,775	$ 3,110	$ 1,829
Deposits and prepaid expenses		1,308	853	457
Total current assets		4,083	3,963	2,286
Property, plant and equipment	6	67,019	46,062	33,723
Exploration and evaluation assets	6	5,197	1,481	1,899
Deferred financing costs		1,642	2,179	-
Total assets		$ 77,941	$ 53,685	$ 37,908
Liabilities				
Bank debt	7	$ 20,541	$ 440	$ 3,046
Trade and other payables		9,884	8,223	3,777
Total current liabilities		30,425	8,663	6,823
Note facility	7	10,000	10,000	-
Decommissioning obligations	8	3,104	1,792	1,450
Total liabilities		43,529	20,455	8,273
Equity				
Share capital	9	37,463	37,282	35,399
Warrants	9	2,065	2,065	-
Contributed surplus	9	3,645	3,331	3,152
Deficit		(8,761)	(9,448)	(8,916)
Total equity		34,412	33,230	29,635
Total equity and liabilities		$ 77,941	$ 53,685	$ 37,908

The notes are an integral part of these condensed financial statements.

SURE ENERGY INC.

Condensed Statements of Income and Comprehensive Income

(in thousands of Canadian dollars, except per share amounts)
(unaudited)

	Note	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
			(note 12)		(note 12)
Petroleum and natural gas revenues		$ 4,972	$ 2,012	$ 16,457	$ 7,250
Royalties		(540)	(175)	(1,740)	(758)
		4,432	1,837	14,717	6,492
Production and operating		1,034	807	3,281	2,330
Transportation		302	114	845	385
Exploration and evaluation		632	40	715	135
General and administrative		337	334	1,882	1,039
Interest and financing charges		546	90	1,458	193
Depletion, depreciation and amortization		1,717	819	5,489	2,664
Stock based compensation		157	166	360	393
		4,725	2,370	14,030	7,139
Net income (loss) and comprehensive income (loss) for the period		$ (293)	$ (533)	$ 687	$ (647)
Earnings per share:					
Basic and diluted	10	$ (0.01)	$ (0.01)	$ 0.01	$ (0.01)

The notes are an integral part of these condensed financial statements.

SURE ENERGY INC.

Condensed Statements of Changes in Equity

(in thousands of Canadian dollars)
(unaudited)

	Note	Nine months ended September 30, 2011 Number	$	Year ended December 31, 2010 Number	$	Nine months ended September 30, 2010 Number	$
				(note 12)		(note 12)	
Share capital							
Balance, beginning of period		48,431,130	37,282	46,873,962	35,399	46,873,962	35,399
Exercise of stock options		117,500	181	1,588,666	1,912	7,000	3
Cancelled		-	-	(31,498)	(29)	(31,498)	(29)
Share capital, end of period		48,548,630	37,463	48,431,130	37,282	46,849,464	35,373
Warrants							
Balance, beginning of period		2,800,000	2,065	-	-	-	-
Issued for Note Facility		-	-	2,800,000	2,065	-	-
Warrants, end of period		2,800,000	2,065	2,800,000	2,065	-	-
Contributed surplus							
Balance, beginning of period			3,331		3,152		3,152
Cancellation of common shares			-		29		29
Exercise of stock options	9		(46)		(560)		-
Stock-based compensation expense			360		710		393
Contributed surplus, end of period			3,645		3,331		3,574
Deficit							
Balance, beginning of period			(9,448)		(8,916)		(8,916)
Net income (loss) for the period			687		(532)		(647)
Deficit, end of period			(8,761)		(9,448)		(9,563)

The notes are an integral part of these condensed financial statements.

SURE ENERGY INC.

Condensed Statements of Cash Flows

(in thousands of Canadian dollars)
(unaudited)

	Note	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Cash flows from operating activities:					
Net income (loss) and comprehensive income (loss) for the period		$ (293)	$ (533)	$ 687	$ (647)
Adjustments for:					
Exploration and evaluation		632	40	715	135
Interest and financing charges		546	90	1,458	193
Depletion, depreciation and amortization		1,717	819	5,489	2,664
Stock based compensation		157	166	360	393
Change in non-cash working capital	11	(1,258)	55	(1,743)	(618)
Net cash from (used in) operating activities		1,501	637	6,966	2,120
Cash flows from investing activities:					
Exploration and evaluation		(40)	(40)	(123)	(135)
Property, plant and equipment expenditures		(10,147)	(3,893)	(18,372)	(7,995)
Acquisition of property, plant and equipment		213	(14)	(11,138)	(155)
Change in non-cash working capital	11	5,310	1,143	3,284	874
Net cash from (used in) investing activities		(4,664)	(2,804)	(26,349)	(7,411)
Cash flows from financing activities:					
Proceeds from issue of share capital		-	-	135	3
Proceeds from loans and borrowings		3,441	2,233	20,101	5,436
Interest paid		(278)	(66)	(853)	(148)
Net cash from financing activities		3,163	2,167	19,383	5,291
Change in cash and cash equivalents		-	-	-	-
Cash and cash equivalents beginning of period		-	-	-	-
Cash and cash equivalents end of period		$ -	$ -	$ -	$ -

The notes are an integral part of these condensed financial statements.

SURE ENERGY INC.

Notes to Condensed Financial Statements

For the three and nine months ended September 30, 2011 and 2010
(tabular amounts are in thousands of Canadian dollars except share and per share information)
(unaudited)

1. Reporting entity:

Sure Energy Inc. ("Sure Energy" or the "Company") is an Alberta incorporated oil and natural gas exploration and production company whose business activities are focused primarily in Alberta. Sure Energy is a public company and trades on the Toronto Stock Exchange. The Company has no subsidiaries. The registered office is located at 1900, 520 3rd Avenue SW, Calgary, Alberta, Canada, T2P 0R3.

2. Basis of preparation:

(a) Statement of compliance:

The condensed financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 Interim Financial Reporting. These condensed financial statements do not include all of the information required for annual financial statements. Amounts relating to the three and nine months ended September 30, 2010 and as at January 1, 2010 and December 31, 2010 were previously presented in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). These amounts have been restated as necessary to be compliant with the Company's accounting policies under International Financial Reporting Standards ("IFRS"). Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 12.

These condensed financial statements were authorized for issue by the Board of Directors on November 8, 2011.

(b) Basis of measurement:

The condensed financial statements have been prepared on the historical cost basis. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

The methods used to measure fair values are disclosed in note 4.

(c) Functional and presentation currency:

These condensed financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments:

The preparation of condensed financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the condensed financial statements including the following:

- Valuation of property, plant and equipment
- Valuation of intangible exploration and evaluation assets
- Measurement of share-based payments
- Provisions and contingencies

Reserve estimates impact a number of the areas referred to above in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently to all periods presented in these condensed financial statements.

(a) Jointly controlled operations and jointly controlled assets:

Many of the Company's oil and natural gas activities involve jointly controlled assets. The condensed financial statements include the Company's share of these jointly controlled assets and its proportionate share of the relevant revenue and related expenses.

(b) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise trade and other receivables, bank debt, note facility, and trade and other payables. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition non-derivative financial instruments are measured as described below.

Financial assets at fair value through profit or loss:

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition attributable transaction costs are recognized in profit or loss when incurred. Financial instruments at fair value through profit or loss are measured at fair value, and changes therein are recognized in profit or loss.

Other:

Non-derivative financial instruments, such as trade and other receivables are classified as loans and receivables. Bank debt, note facility, and trade and other payables are classified as other payables, all of the financial instruments noted above are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant and equipment ("PP&E") and intangible exploration and evaluation ("E&E") assets:

(i) Recognition and measurement:

E&E expenditures and assets:

Pre-license costs are expensed in the statement of income as incurred.

E&E costs, including the costs of acquiring licenses, technical services and studies, and exploration drilling and testing, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. A review of each lease or field is carried out, at least annually, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to PP&E.

PP&E:

Items of PP&E, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. PP&E is grouped into CGU's for impairment testing. IFRS 1 provides an exemption whereby PP&E is valued at deemed cost upon transition to IFRS. Deemed cost is equivalent to the carrying value of PP&E under Canadian GAAP and was allocated to six CGU's under IFRS. The allocation of deemed cost to the CGU's is made based on proved plus probable reserve values. CGU's are aligned with the geographic regions in which Sure Energy operates. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized within "other income" or "other expenses" in profit or loss.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such costs generally represent amounts incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(iii) Depletion and depreciation:

E&E assets are not depleted.

The net carrying value of PP&E is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

(d) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than E&E assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas interests, where facts and circumstances suggest that the carrying amount exceeds the recoverable amount and are assessed for impairment at a minimum, on an annual basis.

For the purpose of impairment testing, assets are grouped together into CGU's, the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(e) Share based payments:

The grant date fair value of options granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. The fair value of an option is measured for each tranche of an option using an estimated forfeiture rate and amortized over the tranche's vesting period.

(f) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value, using a risk-free rate, of management's best estimate of expenditures required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as interest and financing charges whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(g) Revenue:

Revenue from the sale of petroleum and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(h) Interest and financing charges:

Interest and financing charges comprises interest expense on borrowings, accretion on decommissioning obligations and accretion of deferred financing charges.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Deferred financing charges include note facility transaction costs and are amortized over the life of the note facility.

(i) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and at the time of transaction affects neither tax or accounting profit or loss. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied when the asset is realized or liability settled, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(j) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(k) New standards and interpretations not yet adopted:

The Company has not applied the following new and revised IFRS that have been issued but are not yet effective:

(i) IFRS 9 (as amended in 2010) Financial Instruments

IFRS 9 Financial Instruments issued in November 2009 and amended in October 2010 introduces new requirements for the classification and measurement of financial assets and financial liabilities and for derecognition. IFRS 9 requires all recognized financial assets that are within the scope of IAS 39 Financial Instruments: Recognition and Measurement to be subsequently measured at amortized cost or fair value. The most significant effect of IFRS 9 regarding the classification and measurement of financial liabilities relates to the accounting for changes in fair value of a financial liability (designated as at fair value through profit or loss) attributable to changes in the credit risk of that liability. IFRS 9 is effective for annual periods beginning on or after 1 January 2015, with earlier application permitted.

Management of Sure Energy anticipates that IFRS 9 that will be adopted in the Company's financial statements for the annual period beginning January 1, 2015 and that the application of the new Standard could have a significant impact on amounts reported in respect of the Company's financial assets and financial liabilities. However, it is not practicable to provide a reasonable estimate of that effect until a detailed review has been completed.

(ii) IFRS 11 Joint Arrangements ("IFRS 11")
IFRS 11, issued in May 2011, establishes principles for financial reporting by entities involved in a joint arrangement. IFRS 11 supersedes the current IAS 31, "Interests in Joint Ventures" and SIC 13, "Jointly Controlled Entities-Non Monetary Contributions by Venturers" and is effective for reporting periods beginning on or after January 1, 2013. Earlier application is permitted.

(iii) IFRS 13 Fair Value Measurements ("IFRS 13")
IFRS 13, issued in May 2011, defines fair value, sets out a single IFRS framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to IFRS that require or permit fair value measurements or related disclosures, except in specified circumstances. IFRS 13 is to be applied for reporting periods beginning on or after January 1, 2013. Earlier application is permitted.

4. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following hierarchy:

(i) Level 1 – inputs to the valuation methodology are quoted process (unadjusted) for identical assets and liabilities in active markets.

(ii) Level 2 – inputs valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

(iii) Level 3 – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

(a) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment recognized in a business combination, is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the assets with reference to general market conditions, being 12.5% for 2011 (2010: 12.5%).

(b) Trade and other receivables, bank debt and trade and other payables

The fair value of trade and other receivables, bank debt and trade and other payables is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. The fair value of these balances approximated their carrying value due to their short term to maturity.

(c) Note facility:

The carrying value of the note facility approximates it fair value as the fixed interest rate is comparable to interest rates available to the Company.

(d) Stock options:

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

5. Financial risk management:

The Company manages its exposure to financial risks by operating in a manner that minimizes its exposure to the extent practical. The main financial risks affecting the Company are as follows:

(a) Credit Risk

Credit risk is primarily related to the Company’s receivables from petroleum and natural gas marketers and joint venture partners and the risk of financial loss if a customer, partner or counterparty to a financial instrument fails to meet its contractual obligations. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production and the Company could be at risk for up to 55 days of production from any marketer. The Company sells its production to several petroleum and natural gas marketers so that the exposure to any one entity is minimized. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. The Company does not typically obtain collateral from joint venture partners; however in certain circumstances, it may cash call a partner in advance of the work being performed. The Company establishes an allowance for doubtful accounts as determined by management based on their assessment of collection therefore the carrying amount of accounts receivable generally represents the maximum credit exposure. The maximum exposure to credit risk at the balance sheet date was equal to the carrying value of accounts receivable. As of September 30, 2011, substantially all receivables were current and there were no receivables provided for or written off during the nine months ended September 30, 2011.

(b) Market Risk

Market risk consists of commodity price, foreign currency and interest rate risks.

(i) Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand. The Company has no financial derivative sales contracts in place as at or during the period ended September 30, 2011.

(ii) Foreign Currency Exchange Risk

Foreign currency exchange rate risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company’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 Company had no forward exchange rate contracts in place as at or during the period ended June 30, 2011.

(iii) Interest Rate Risk

Interest rate cash flow risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. If interest rates on the bank debt increased by one percent, net income would have decreased by $79,000 during the nine months ended September 30, 2011.

(c) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company’s approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due without incurring unacceptable losses or risking harm to the Company’s reputation. The Company prepares capital expenditures budgets which are regularly monitored and updated as considered necessary. As well, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Company has bank debt that is reviewed periodically by the lender and a note facility.

(d) Capital Management

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence, and to sustain future investing in oil and gas activities which may or may not be successful. The objective is to balance the proportion of debt and equity in its capital structure. The Company defines its capital structure to include shareholders' equity, bank debt, the note facility and working capital. The key measures that the Company utilizes in evaluating its capital structure are net debt to funds flow from operations, net debt as a percent of total capitalization and the current credit available from its creditors in relation to the Company's budgeted capital program. Funds flow from operations is a non-GAAP measure and it is used by the Company to analyze operating performance, leverage and liquidity. The Company's capitalization and calculation of funds flow from operations is as follows:

	September 30, 2011	December 31, 2010
Net debt		
Working capital		
Trade and other receivables	(2,775)	(3,110)
Deposits and prepaid expenses	(1,308)	(853)
Trade and other payables	9,884	8,223
	5,801	4,260
Note facility	10,000	10,000
Bank debt	20,541	440
Total net debt	36,342	14,700
Market capitalization		
Common shares outstanding	48,548,630	48,431,130
Closing price, TSX	1.30	1.75
Total market capitalization	63,113	84,754
Total net debt and market capitalization	99,455	99,454
Net debt as a percent of total capitalization	37%	15%

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
Funds flow from operations:			
Net income (loss) for the period	(293)	687	(532)
Adjustments:			
Exploration and evaluation expenditures	632	715	602
Depletion, depreciation and amortization	1,717	5,489	4,860
Impairment	-	-	423
Interest and financing charges	546	1,458	344
Stock based compensation	157	360	710
Total funds flow from operations	2,759	8,709	6,407
Trailing 12 months funds flow from operations		12,380	6,407
Net debt to trailing 12 months funds flow from operations ratio		2.94	2.29

The Company also assesses its capital structure by forecasting cash flows and estimated debt levels. There are several strategies to maintain or adjust capital structure including increasing bank credit as a result of reserve growth, decreasing capital spending and new equity issues.

The Company is subject to a covenant on its credit facility to maintain its ratio of current assets (including the undrawn portion of the credit facilities) to current liabilities (not including current bank debt) at a 1.0:1.0 level. As at September 30, 2011, the ratio was 1.88 (December 31, 2010 - 2.25).

6. PP&E and E&E assets:

	PP&E	E&E Assets	Total
Cost or deemed cost:			
Balance at January 1, 2010	$ 33,743	$ 1,899	$ 35,642
Expiries	-	(418)	(418)
Additions	17,622	-	17,622
Balance at December 31, 2010	51,365	1,481	52,846
Expiries	-	(592)	(592)
Additions	26,446	4,308	30,754
Balance at September 30, 2011	$ 77,811	$ 5,197	$ 83,008
Depletion, depreciation and impairments:			
Balance at January 1, 2010	20	-	20
Depletion and depreciation for the year	4,860	-	4,860
Impairment	423	-	423
Balance at December 31, 2010	5,303	-	5,303
Depletion and depreciation for the period	5,489	-	5,489
Balance at September 30, 2011	10,792	-	10,792
Carrying amounts:			
At January 1, 2010	$ 33,723	$ 1,899	$ 35,622
At December 31, 2010	$ 46,062	$ 1,481	$ 47,543
At September 30, 2011	$ 67,019	$ 5,197	$ 72,216

At December 31, 2010, an impairment loss was recorded for the Tweedie cash generating unit. The impairment was due to low market prices for natural gas at December 31, 2010.

7. Bank debt and note facility:

At September 30, 2011, Sure Energy had total credit facilities of $45.0 million consisting of a $25 million bank credit facility and a $20 million note facility. At September 30, 2011, $30.5 million was drawn on the credit facilities.

8. Decommissioning obligations:

	September 30 2011	December 31 2010
Carrying amount, beginning of period	$ 1,792	$ 1,450
Drilling additions	1,099	279
Acquisition of property, plant and equipment	145	-
Accretion	68	63
Carrying amount, end of period	3,104	1,792

9. Share capital:

During the year ended December 31, 2010, 1.6 million stock options and Performance Incentive Rights were exercised for a total cash consideration of $1.4 million. Due to the exercise of the stock options, $560,000 should have been transferred out of contributed surplus to share capital. This amount reflects the stock based compensation that was previously recorded attributable to these options. This amount was not recorded in the year ended December 31, 2010 but has been correct in these financial statements. Contributed surplus was decreased by $560,000 and share capital was increased as at December 31, 2010 for this restatement.

During the nine months ended September 30, 2011, 117,500 stock options and Performance Incentive Rights were exercised for a total cash consideration of $135,000. Due to the exercise of the stock options, $46,000 was transferred out of contributed surplus to share capital. This amount reflects the stock based compensation that was previously recorded attributable to these options.

On May 25, 2011, Sure Energy extended the term of certain options from five to seven years. The options extended were 1,385,000 stock options granted on August 22, 2006 at an exercise price of 1.28, 530,334 stock options granted on November 7, 2008 at an exercise price of $0.39 and 1,158,000 stock options granted on May 14, 2010 at an exercise price of $0.98. The terms were extended so that all of the Company's options have a term of seven years. All of the options were in the money as of May 25, 2011. There was no impact on the accounting for the stock options as all stock options, which now have a seven year life, are valued having an expected life of five years.

10. Earnings per share:

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2011	2010	2011	2010
Profit (loss)	$ (293)	$ (533)	$ 687	$ (647)
Earnings per share – basic	(0.01)	(0.01)	0.01	(0.01)
Weighted average shares outstanding - basic	48,548,630	46,849,464	48,534,866	46,848,678

Diluted earnings per share is not disclosed because all in-the-money options, PIRs and warrants are anti-dilutive.

11. Supplemented cash flow information:

Changes in non-cash working capital items are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Trade and other receivables	$ (748)	$ 31	$ 335	$ 265
Deposits and prepaid expenses	(193)	(175)	(455)	(128)
Trade and other payables	4,993	1,342	1,661	119
	$ 4,052	$ 1,198	$ 1,541	$ 256
Operating activities	$ (1,258)	$ 55	$ (1,743)	$ (618)
Investing activities	$ 5,310	$ 1,143	$ 3,284	$ 874

12. Subsequent event:

On November 8, 2011 the bank credit facility was increased to $33 million increasing total credit facilities to $53 million.

13. Reconciliation of statement of financial position from Canadian GAAP to IFRS:

At the date of IFRS transition – January 1, 2010:

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Trade and other receivables		$ 1,829	$ -	$ 1,829
Deposits and prepaid expenses		457	-	457
		2,286	-	2,286
Property, plant and equipment		35,622	(1,899)	33,723
Exploration and evaluation assets		-	1,899	1,899
		$ 37,908	$ -	$ 37,908
Liabilities				
Bank debt		$ 3,046	$ -	$ 3,046
Trade and other payables		3,777	-	3,777
		6,823	-	6,823
Decommissioning obligations		1,031	419	1,450
		7,854	419	8,273
Equity				
Share capital		35,732	(333)	35,399
Contributed surplus		3,152	-	3,152
Deficit		(8,830)	(86)	(8,916)
		30,054	(419)	29,635
		$ 37,908	$ -	$ 37,908

At the end of the last reporting year under Canadian GAAP – December 31, 2010:

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Trade and other receivables		$ 3,110	$ -	$ 3,110
Deposits and prepaid expenses		853	-	853
		3,963	-	3,963
Property, plant and equipment		45,375	687	46,062
Exploration and evaluation assets		-	1,481	1,481
Deferred financing costs		2,179	-	2,179
		$ 51,517	$ 2,168	$ 53,685
Liabilities				
Bank debt		$ 440	$ -	$ 440
Trade and other payables		8,223	-	8,223
		8,663	-	8,663
Note facility		10,000	-	10,000
Decommissioning obligations		1,276	516	1,792
		19,939	516	20,455
Equity				
Share capital		37,615	(333)	37,282
Warrants		2,065	-	2,065
Contributed surplus		3,331	-	3,331
Deficit		(11,433)	1,985	(9,448)
		31,578	1,652	33,230
		$ 51,517	$ 2,168	$ 53,685

At the end of the last comparative quarter – September 30, 2010:

	Notes	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Trade and other receivables		$ 1,564	$ -	$ 1,564
Deposits and prepaid expenses		585	-	585
		2,149	-	2,149
Property, plant and equipment		38,887	415	39,302
Exploration and evaluation assets		-	1,899	1,899
		$ 41,036	$ 2,314	$ 43,350
Liabilities				
Bank debt		$ 3,896	$ -	$ 3,896
Trade and other payables		8,481	-	8,481
		12,377	-	12,377
Decommissioning obligations		1,156	433	1,589
		13,533	433	13,966
Equity				
Share capital		35,706	(333)	35,373
Contributed surplus		3,574	-	3,574
Deficit		(11,777)	2,214	(9,563)
		27,503	1,881	29,384
		$ 41,036	$ 2,314	$ 43,350

Reconciliation of condensed statement of income for the year ended December 31, 2010:

	Notes		Canadian GAAP		Effect of transition to IFRS		IFRS
Petroleum and natural gas revenues		$	13,063	$	-	$	13,063
Royalties			(1,108)		-		(1,108)
			11,955		-		11,955
Production and operating			3,432		-		3,432
Transportation			645		-		645
Exploration and evaluation			-		602		602
General and administrative			1,328		143		1,471
Interest and financing charges			281		63		344
Depletion, depreciation and amortization			8,162		(3,302)		4,860
Impairment			-		423		423
Stock based compensation			710		-		710
			14,558		(2,071)		12,487
(Loss) income and comprehensive (loss) income for the year		$	(2,603)	$	2,071	$	(532)

Reconciliation of condensed statement of income for the nine months ended September 30, 2010:

	Notes		Canadian GAAP		Effect of transition to IFRS		IFRS
Petroleum and natural gas revenues		$	7,250	$	-	$	7,250
Royalties			(758)		-		(758)
			6,492		-		6,492
Production and operating			2,330		-		2,330
Transportation			385		-		385
Exploration and evaluation			-		135		135
General and administrative			924		115		1,039
Interest and financing charges			148		45		193
Depletion, depreciation and amortization			5,259		(2,595)		2,664
Stock based compensation			393		-		393
			9,439		(2,300)		7,139
(Loss) income and comprehensive (loss) income for the period		$	(2,947)	$	2,300	$	(647)

Notes to reconciliations

(a) IFRS 1 exemptions

These are the Company's Condensed Interim Financial Statements for periods covered by the first annual financial statements presented in accordance with IFRS for the year ending December 31, 2011.

IFRS was applied retrospectively at the transition date with all adjustments to assets and liabilities as stated under Canadian GAAP taken to retained earnings unless certain exceptions and exemptions are applied.

IFRS 1, "First-Time Adoption of International Financial Reporting Standards", permitted first time adopters of IFRS a number of exemptions. The Company elected to utilize the following exemptions for first-time adoption of IFRS:

(i) IFRS 1, First-Time Adoption of International Financial Reporting Standards, whereby the petroleum asset balance as determined under Canadian GAAP was allocated to the IFRS categories of exploration and evaluation assets and PP&E. Under the exemption, for assets in the development or production phases, the amount was allocated to the underlying IFRS transitional assets on a pro-rata basis using proved and probable reserve values as of the IFRS transition date. This resulted in a $1.9 million increase in exploration and evaluation assets with a corresponding decrease in PP&E.

(ii) IFRS 3, Business Combinations, which allows for an implementation of the IFRS business combination rules on a prospective basis, therefore, business combinations entered into prior to January 1, 2010 were not retrospectively restated;

(iii) IFRS 2, Share-based payments, whereby stock options that vested prior to January 1, 2010 are not required to be retrospectively restated. Therefore, IFRS requirements apply only to those options that were unvested at the date of transition;

(iv) IFRS 23, Borrowing Costs, whereby borrowing cost disclosures relating to qualifying assets are applied prospectively from the IFRS transition date.

(b) Decommissioning obligations:

Under Canadian GAAP, decommissioning obligations were discounted at a credit adjusted risk free rate of 8 percent. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted, therefore, the provision is discounted at a risk free rate of 4 percent. Upon transition to IFRS, this resulted in a $0.4 million increase in the decommissioning obligations with a corresponding decrease in retained earnings.

Under Canadian GAAP, accretion of the discount was included in depletion and depreciation. Under IFRS it is included in interest and financing charges.

(c) Flow-through shares:

For Canadian GAAP, equity is reduced for the value of the tax pools renounced to flow-through shareholders. Under IFRS, equity is reduced by the premium paid for the flow-through share versus a non-flow-through share. The Company issued 1.9 million flow-through shares in 2008. Share capital is approximately $0.3 million less under IFRS than Canadian GAAP for this difference, with a corresponding increase to retained earnings.

(d) Depletion policy:

Upon transition to IFRS, the Company adopted a policy of depleting PP&E on a unit of production basis over proved and probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e. fields or combinations thereof).

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

For the year ended December 31, 2010, this resulted in a decrease to depletion of $3.3 million (nine months ended September 30, 2010 - $2.6 million) with a corresponding change to PP&E. An impairment of $0.4 million was also recorded for the year ended December 31, 2010.

(e) Directly attributable salaries and benefits:

Certain salaries and benefits were capitalized under Canadian GAAP and not under IFRS. For the year ended December 31, 2010, this resulted in an increase in general and administrative expenses of $143,000 (nine months ended September 30, 2010 - $115,000) and a corresponding decrease in PP&E.

(f) Statement of cash flows:

Under Canadian GAAP, interest paid was classified as operating. Under IFRS, interest paid is classified as financing. For the year ended December 31, 2010 this resulted in an increase in net cash from operating activities of $251,000 (nine months ended September 30, 2010 - $148,000) and a corresponding decrease to cash flows from financing activities.

Directors	Officers	Advisors
Jeffrey S. Boyce Calgary, Alberta	Jeffrey S. Boyce Chairman and Chief Executive Officer	*Auditors* Deloitte & Touche LLP Calgary, Alberta
W. Peter Comber [1, 3, 4] Managing Director, Barrantagh Investment Management Inc. Toronto, Ontario	Chris Baker President, Chief Operating Officer and VP, Exploration	*Banker* The National Bank Calgary, Alberta
Larry J. Macdonald [1, 2, 3, 4] Chairman & CEO, Point Energy Ltd. Calgary, Alberta	Lance Wirth Vice President, Finance and Chief Financial Officer	*Evaluation Engineers* Sproule Associates Limited Calgary, Alberta
Thomas P. Stan [1, 2, 4] President & CEO, Foundation Oil and Gas, Calgary, Alberta	C. Tom Banks Vice President, Engineering	*Legal Counsel* Borden Ladner Gervais LLP Calgary, Alberta
[1] Audit Committee [2] Governance & Human Resources Committee [3] Environment, Health & Safety Committee [4] Independent Reserves Committee	Daniel G. Kolibar Corporate Secretary	*Transfer Agent* Valiant Trust Company Calgary, Alberta
	Rob Sheedy Vice President, Land	*Stock Exchange Listing* The Toronto Stock Exchange Symbol: SHR
	Dale Kuzyk Vice President, Production	

Sure Energy Inc. is a publicly traded oil and gas exploration and development company listed on the Toronto Stock Exchange under the symbol "SHR".

For further information, please visit our website at www.sureenergyinc.com or contact:

Mr. Jeff Boyce, Chairman and CEO	Mr. Chris Baker, President, COO & VP Exploration	Mr. Lance Wirth, VP Finance and CFO

Forward-looking Information

Certain statements contained in this third quarter report constitute forward-looking information. These statements relate to future events or Sure Energy's future performance. The use of any of the words "could", "expect", "believe", "will", "projected", "estimated" and similar expressions and statements relating to matters that are not historical facts are intended to identify forward-looking information and are based on Sure Energy's current belief or assumptions as to the outcome and timing of such future events. Actual future results may differ materially. In particular, Sure Energy's stated intentions and expectations for drilling, fracture stimulation, development and production on its, Queensdale, Virginia Hills and Hatton properties, statements under "Outlook" with respect to the impact on production from frac'ing at Virginia Hills, intended development work at Hatton and improving economics at Redwater; statements in the management's discussion and analysis related to commencement of production of the six wells drilled in the third quarter, expectations with respect to general and administrative costs, expectations for the payment of current income tax and in the section "Outlook", are forward looking information. Sure Energy's Annual Information Form and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com) describe the risks, material assumptions and other factors that could influence actual results and which are incorporated herein by reference. Sure disclaims any intention or obligation to publicly update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as may be expressly required by applicable securities laws.

Corporate Head Office:
Suite 1100, 606 4th Street S.W.
Calgary, Alberta T2P 1T1
Telephone: (403) 410-3100
Facsimile: (403) 410-3111
Email: info@sureenergyinc.com
Web: www.sureenergyinc.com