SOUTHERN PACIFIC
RESOURCE CORP.

Management's Discussion and Analysis for the

Three and Nine Months Ended March 31, 2012

OVERVIEW

Southern Pacific Resource Corp. ("Southern Pacific" or the "Company") is engaged in the exploration for and development of in-situ oil sands in the Athabasca region of Alberta and the thermal production of heavy oil in Senlac, Saskatchewan. The Company's head office is located in Calgary, Alberta, Canada. Southern Pacific's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "STP." Additional information relating to Southern Pacific can be found on SEDAR at www.sedar.com and on Southern Pacific's website at www.shpacific.com.

In this Management's Discussion and Analysis ("MD&A"), references to "Southern Pacific" or the "Company" refer to Southern Pacific Resource Corp. and its subsidiaries on a consolidated basis. The terms "2011" and "2010" are used throughout this document and refer to the fiscal years ended June 30, 2011 and 2010, respectively. References to "third quarter 2012" in this document refer to the three month financial period ended March 31, 2012. References to "first quarter 2012" or "second quarter 2012" in this document refer to the three month financial period ended September 30, 2011 or December 31, 2011 respectively. References to "third quarter 2011" in this document refer to the comparative three month financial period ended March 31, 2011.

The following MD&A is a review of the operations, current financial position and outlook for Southern Pacific and is prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended June 30, 2011 and the unaudited consolidated financial statements for the nine months ended March 31, 2012. This MD&A is dated May 14, 2012. The financial statements and financial data contained in this MD&A are part of the Company's first year of financials that have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") in Canadian currency. As such, the comparative periods have been restated to conform to the new IFRS standards. The adoption of IFRS does not impact the underlying economics of Southern Pacific's operations. Previously, the Company prepared its interim and annual financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP").

OVERALL PERFORMANCE

Highlights for the quarter ended March 31, 2012 include the following:

- Achieved funds from operations of $16.5 million for the quarter compared to $9.3 million in the third quarter of 2011, an increase of 77%. Higher oil prices and lower operating costs generated the near record cash flow during the quarter;
- Averaged overall production from STP-Senlac of 4,154 barrels per day ("bbl/day") for the quarter compared to 3,627 bbl/day in the third quarter of 2011;
- Continued strong execution on the construction of STP-McKay Phase 1 Thermal Project ("STP-McKay Phase 1"). The commissioning of the Central Process Facility ("CFP") commenced on May 14, 2012, initiating with the cogen and utilities plants. After permanent power is established, a sequential startup of the remaining CPF process systems will occur, and first steam should be delivered to the SAGD well pairs towards the end of June 2012 with oil production commencing three to four months after first steam. The total capital cost projection remains at $440 million as compared to the original budget of $450 million; and

- Announced expansion plans for its STP Phase 1 project by 50%, which would give the project total plant capacity of 18,000 bbl/day. This will allow the Company to accelerate its production growth forecast.

OUTLOOK

Senlac

The Company completed drilling and tie-in of Phase J at Senlac in December 2011, which consists of three SAGD well pairs. Circulation steam on the first well pair commenced in mid December and first oil was produced from the well pair on December 29, 2011. The second and third well pairs were brought on production in January and March respectively. With these three additional well pairs on stream, Senlac production averaged over 4,154 bbl/day generating near record cash flow of $16.5 million for the quarter. Plans to drill and equip the next phase are now underway, with an expectation to have it ready for operation in the fourth quarter of calendar 2012.

STP-McKay Phase 1 Construction Update

Construction of STP-McKay Phase 1 continues to advance very well. All of the Central Process Facility ("CPF") equipment packages and modules have been delivered to the site. The permanent operating team is now fully staffed with 45 Southern Pacific employees; they are deployed on the project site and preparing for startup and operations. Commissioning of the CPF commenced May 14, 2012, initiating with the cogen and utilities plants. After permanent power is established, a sequential startup of the remaining CPF process systems will occur, and first steam should be delivered to the SAGD well pairs towards the end of June 2012. After first steam, the wellbores will be circulated and warmed with steam for a period of three to four months, after which bitumen production will commence. It is expected to take approximately 12 months for production to ramp up to capacity after steam circulation has been completed.

The project's total projected capital cost estimate remains at $440 million, as compared to the original budget of $450 million. As of March 31, 2012 approximately $400 million of capital has been incurred or committed on the project. As most of the equipment and modules have been included within the incurred amount, the remaining capital estimate is not expected to vary significantly through to the conclusion of the construction and startup. It should also be noted that the cost estimate includes $15 million of scope changes to the original design that were added to further increase the reliability of the overall process. These additions will also be utilized within the Phase 1 Expansion.

Arrangements for the transportation and marketing of the bitumen production out of the STP-McKay Thermal Project are currently being finalized. The Company will release more details upon completion of these arrangements.

STP-McKay Phase 1 Expansion

On May 10, 2012, Southern Pacific announced expansion plans for its steam assisted gravity drainage ("SAGD") STP-McKay Thermal Project to a design capacity of 18,000 bbl/day. The expansion is anticipated to significantly reduce future overall capital costs in the entire project and accelerate the Company's production growth forecast. Southern Pacific's internal technical team have identified a unique opportunity to expand the existing STP-McKay Phase 1 central process facilities ("Phase 1 Expansion") by as much as 50% (6,000 bbl/day of bitumen based on a steam-oil ratio ("SOR") of 2.8) at an estimated cost of approximately $25,000 per barrel of designed capacity, or $150 million, including additional well pairs. The expansion plans have been in the engineering design phase for three months and based on analysis over that period, the

Company has elected to proceed with expanding STP-McKay Phase 1 prior to the construction of STP-McKay Phase 2.

The expansion takes advantage of excess capacity that was incorporated into the original design and construction of Phase 1. Phase 1 currently has additional water treatment capacity that can be accessed with minimal capital investment, allowing the facility to treat approximately 50,400 bbl/d of water. Additional steam generation will be required to convert an incremental 16,400 bbl/d (50,400 bbl/d total) of treated water to steam. A fourth cogeneration turbine will also be required to supplement the power demand of the expanded facilities. The remainder of the facility expansion will be limited to piping modifications and small equipment additions. The entire expansion will fit comfortably within the existing Phase 1 central process facility site, making this expansion both cost effective and environmentally responsible.

Approval for the Phase 1 Expansion will be incorporated into the STP-McKay Phase 2 approval process. An application for Phase 2 was submitted in November, 2011. Phase 2 is a separate facility, located approximately 5 km east of Phase 1 and on the east side of the McKay River. Southern Pacific plans to provide an update to the application which will include the plans for the 6,000 bbl/d Phase 1 Expansion. Concurrently, the Phase 2 project will have its design capacity reduced from 24,000 bbl/day to 18,000 bbl/day, resulting in the total STP-McKay project area retaining the same overall capacity of 36,000 bbl/day of bitumen. There are a number of advantages to this approach. Phase 2 will be designed using a very similar design to Phase 1. This should reduce the total capital cost for Phase 2, which was originally being designed with two integrated 12,000 bbl/day facility streams. The overall layout of Phase 2 will likely be smaller, further reducing cost and environmental footprint. From a reserves perspective, having additional capacity in Phase 1 will better balance the capacity and reserve distribution between the west and east sides of the McKay River, which will minimize the requirement for future river crossings.

Southern Pacific does not expect this revision to significantly delay the application approval process as the changes are minimal from an environmental or regulatory perspective; virtually every modification can be viewed as an improvement to the overall scheme. Southern Pacific has already consulted with the Alberta regulators on the modification, and the appropriate steps are being taken to accommodate the new Phase 1 Expansion plans within the original Phase 2 application. Additionally, the Phase 1 Expansion can be expedited upon approval, with a current estimate of only nine months to construct. This will provide the Company with accelerated cash flow from the 6,000 bbl/day expansion, prior to Phase 2 startup. Assuming regulatory approval occurs in the fourth quarter of 2013, expansion volumes could be realized from Phase 1 before the end of 2014.

The Phase 1 Expansion is significant to STP; it enhances the ability of the Company to grow internally. Expected cash flow using current pricing from STP-Senlac and STP-McKay Phase 1, coupled with STP's existing debt facilities, could fully provide funding necessary for the Phase 1 Expansion. Further along those lines, the Company would expect lower costs of capital funding for the Phase 2 project with the expanded cash flows from the Phase 1 Expansion and lower Phase 2 capital costs.

RESULTS OF OPERATIONS

Production

	Three Months Ended March 31,			Nine Months Ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Heavy oil (bbl/day)	**4,154**	3,627	15%	**3,717**	4,018	(7%)
Natural gas (mcf/day)	**13**	223	(94%)	**66**	201	(67%)
Total (boe/day)	**4,156**	3,664	13%	**3,728**	4,052	(8%)

Heavy oil production for the quarter ended March 31, 2012 averaged 4,154 bbl/day, an increase of 15% over the same period in 2011. The increase is attributable to the Phase J well pairs now on production. Natural gas production was lower quarter over quarter as the company sold its remaining conventional assets in July 2011.

For the nine months ended March 31, 2012 the heavy oil production averaged 3,717 bbl/day, a 7% decrease from the same period in 2011. The decrease is attributable to natural declines that are offset with the Phase J well pairs now on production, as discussed above. The natural gas declines are the result of the sale of non-core assets in the first quarter of 2012.

Product Prices

	Three Months Ended March 31,			Nine Months Ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Heavy oil ($ per bbl)	**64.49**	57.27	13%	**65.52**	57.00	15%
Natural gas ($ per mcf)	**2.96**	3.76	(21%)	**3.32**	3.72	(11%)
Combined average ($ per boe)	**64.52**	56.98	13%	**65.50**	56.75	15%

The heavy oil price received by Southern Pacific was $64.49 per bbl for the three months ended March 31, 2012, 13% higher than the same quarter in the prior year. The increase in the heavy oil price for the third quarter of 2012 is largely attributable to the increase in the WTI crude oil price partially offset by an increase in the heavy oil differential. Southern Pacific has entered into commodity hedging contracts to mitigate fluctuations in commodity prices and the heavy oil differential as outlined under the "Risk Management Activities and Commitments" section below. The decrease in natural gas pricing was expected given current natural gas markets.

For the nine months ended March 31, 2012 the heavy oil price increased 15% over the prior year to $65.52 per bbl. The increase was due to higher WTI pricing offset with higher heavy oil differentials. Natural gas prices decreased for the nine months ended March 31, 2012 consistent with the third quarter 2012 and natural gas market conditions.

Operating Netbacks

($ per boe)	Three Months Ended March 31, 2012	2011	Change	Nine Months Ended March 31, 2012	2011	Change
Combined average	**64.52**	56.98	13%	**65.50**	56.75	15%
Royalties	**(11.48)**	(9.93)	16%	**(10.93)**	(10.06)	9%
Operating costs	**(8.63)**	(11.59)	(26%)	**(10.55)**	(10.54)	0%
Operating netback	**44.41**	35.46	25%	**44.02**	36.15	22%

Operating netbacks for the quarter and nine months ended March 31, 2012 increased by 25% and 22% respectively, over the same periods in the prior year. This increase is primarily due to the higher average combined product prices received, offset by higher royalty costs and for the quarter ended March 31, 2012, lower operating costs.

Oil and Gas Revenue

($ thousands)	Three Months Ended March 31, 2012	2011	Change	Nine Months Ended March 31, 2012	2011	Change
Heavy oil	**24,395**	18,715	30%	**67,096**	62,802	7%
Natural gas	**4**	76	(95%)	**60**	204	(71%)
Total oil and gas revenue	**24,399**	18,791	30%	**67,156**	63,006	7%

Total oil and gas revenue for the quarter and nine months ended March 31, 2012 was $24.4 million and $67.2 million respectively. The increase from the comparative prior periods of 30% and 7% is due to higher realized heavy oil pricing and for the quarter ended March 31, 2012, higher production volumes. The natural gas revenue decreased as a result of the sale of the non-conventional assets on July 15, 2011 and reduced natural gas pricing.

Other Income

For the quarter and nine months ended March 31, 2012 Southern Pacific recorded $1.5 million in other income. The majority of the funds received were a result of an audit pertaining to the Senlac acquisition and operations.

Risk Management Contracts

($ thousands)	Three Months Ended March 31, 2012	2011	Change	Nine Months Ended March 31, 2012	2011	Change
Unrealized (loss) gain	**4,477**	(4,671)	-	**2,183**	(5,673)	-
Realized gain	**738**	138	435%	**1,132**	162	599%
Risk management contracts	**5,215**	(4,533)	-	**3,315**	(5,511)	-

For the quarter and nine months ended March 31, 2012, Southern Pacific recorded an unrealized gain on risk management contracts of $4.5 million and $2.2 million respectively, compared to an unrealized loss of $4.7 million and $5.7 million for the same periods in 2011. The unrealized gains for fiscal 2012 are attributable to the fixed oil differential contracts offset with losses on the oil collars. The unrealized losses for the prior three and nine months ended March 31, 2011 were largely attributable to the gradual increase in the WTI oil price reducing the value of the oil collars.

The realized gain of $0.7 million for the quarter ended March 31, 2012 is attributable to the fixed oil differential contracts and foreign exchange hedges. For the nine months ended March 31, 2012 the gain of $1.1 million is related to oil and foreign exchange hedges as well as fixed gas price contracts. The realized gains or losses on the risk management contracts represent actual cash received or paid by Southern Pacific as its hedged price either exceeded or was less than the market price. The intent of these risk management contracts is to protect the downside risk to the Company's cash flow to pursue Southern Pacific's growth plan at STP-McKay. The contracts are listed in detail in the Commitments section of this MD&A.

Royalties

($ thousands except for % and per boe)	Three Months Ended March 31,			Nine Months Ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Royalties	**3,925**	2,959	33%	**10,054**	10,105	(1%)
Provincial resource surcharges	**415**	315	32%	**1,148**	1,062	8%
	4,340	3,274	33%	**11,202**	11,167	0%
% of oil and gas revenue	**17.8%**	17.4%	-	**16.7%**	17.7%	-
Per boe	**$11.48**	$9.93	16%	**$10.93**	$10.06	9%

The royalty rates at Senlac are on a sliding scale dependent upon the level of capital spending and operating costs. An increase in capital and operating spending reduces the royalty rate and likewise a reduction in capital and operating spending will increase the royalty rate. Also included within royalties, are provincial resource surcharges that are charged by the province of Saskatchewan and are determined as a fixed percentage of provincial resource revenues generated from the Company's Senlac property.

Royalties for the quarter ended March 31, 2012 were $4.3 million, compared to $3.3 million for the same quarter in 2011. The royalties represented 17.8% of total petroleum and natural gas revenue which is comparable to the same quarter in 2011 at 17.4%. On an absolute basis the royalties are higher due to increased revenues.

Royalties for the nine months ended March 31, 2012 and 2011 were $11.2 million, which represented 16.7% and 17.7% respectively of the total petroleum and natural gas revenue. The overall slight decrease in the royalty rate for the nine months ended March 31, 2012 is attributable to higher capital spending relative to the prior year.

Operating Costs

($ thousands except for per boe)	Three Months Ended March 31,			Nine Months Ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Other operating costs	**1,873**	2,067	(9%)	**7,141**	7,563	(6%)
Natural gas costs	**1,389**	1,754	(21%)	**3,673**	4,133	(11%)
Operating costs	**3,262**	3,821	(15%)	**10,814**	11,696	(8%)
Per boe	**$8.63**	$11.59	(26%)	**$10.55**	$10.54	0%

Other operating costs for the quarter and nine months ended March 31, 2012 decreased by 9% and 6% respectively, compared to the same periods in 2011. The decrease in the quarter is attributable to fewer workover costs at Senlac. For the nine months ended March 31, 2012 and 2011 the operating costs are comparable on a per BOE basis.

A significant component of the operating costs is the purchase of natural gas, which is used to create steam for the thermal recovery of heavy oil. Southern Pacific manages its natural gas price risk by selectively hedging, or purchasing fixed price contracts, on a portion of its natural gas purchases throughout the year. For the quarter and nine months ended March 31, 2012 the natural gas costs decreased by 21% and 11% respectively compared to the same periods in 2011. The decrease is the result of lower natural gas prices.

In total, operating costs were $3.3 million for the quarter ended March 31, 2012, compared to $3.8 million for the same quarter in 2011. For the nine months ended March 31, 2012 total operating costs at $10.8 million were 8% less than the prior year. On a per barrel basis, for the quarter ended March 31, 2012 the operating costs decreased to $8.63 from $11.59 in the prior quarter of 2011 and for the nine months ended March 31, 2012 the operating costs are comparable at $10.55 versus $10.54 in 2011.

Exploration and Evaluation Expenses

Exploration and evaluation expenses for the third quarter 2012 were $nil compared to $10,000 for the third quarter 2011. For the nine months ended March 31, 2012 the exploration and evaluation expenses were $nil compared to $0.4 million for the same period in fiscal 2011. In both periods the exploration and evaluation expenses relate to lease expiries on undeveloped lands.

General and Administrative Expenses

	Three Months Ended March 31,			Nine Months Ended March 31,		
($ thousands except for per boe)	**2012**	2011	Change	**2012**	2011	Change
General and administrative expenses	**2,495**	2,626	(5%)	**8,452**	6,340	33%
Per boe	**$6.60**	$7.96	(17%)	**$8.24**	$5.71	44%

General and administrative expenses for the quarter ended March 31, 2012 were 5% lower compared to the same period in 2011. The decrease is the result of bonuses being paid in the prior year during the three months ended March 31, 2011. For the nine months ended March 31, 2012 the increase is due to additional personnel hired and administration costs required for STP-McKay Phase 1 that is under construction.

Finance Expenses

	Three Months Ended March 31,			Nine Months Ended March 31,		
($ thousands except for per boe)	**2012**	2011	Change	**2012**	2011	Change
Interest and financing	**168**	34	394%	**438**	183	139%
Accretion	**1**	24	(96%)	**56**	49	14%
	169	58	191%	**494**	232	113%
Per boe	**$0.45**	$0.18	150%	**$0.48**	$0.21	129%

Finance expenses for the quarter and nine months ended March 31, 2012 were higher than the previous period by 394% and 139% respectively, due to the increase in standby fees related to the new credit facility. Interest costs of $12.2 million and $36.4 million are capitalized as part of STP-McKay Phase 1 for the quarter and nine months ended March 31, 2012 respectively.

Southern Pacific has recorded a decommissioning liability that represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities.

The liability will be increased over time based on new obligations including: wells drilled, constructing facilities, acquiring operations, or adjusting future estimates related to timing, discount rates and dollar amounts. Similarly, the liability can be reduced as actual abandonment costs are undertaken, decreasing future obligations. The accretion charge of $1,000 for the quarter ended March 31, 2012 represents the change in the estimated time value of the decommissioning liability. The decrease in the accretion over the prior year is due to the sale of the conventional assets in July 2011. Currently the discounted liability is estimated at $37.6 million and will be accreted up to the estimated undiscounted liability of $83.3 million over the remaining economic life of the Company's assets.

Depletion and Depreciation

	Three Months Ended March 31,			Nine Months Ended March 31,		
($ thousands except for per boe)	**2012**	2011	Change	**2012**	2011	Change
Depletion and depreciation	**7,258**	6,317	15%	**19,432**	22,249	(13%)
Per boe	**$19.19**	$19.16	0%	**$18.95**	$20.04	(5%)

Depletion and depreciation expense for the quarter ended March 31, 2012 increased over the prior period in 2011 by 15%. The increase was the result of significant asset additions augmenting the depletion base; however, on a per barrel basis the two quarters are comparable as production was higher in the third quarter 2012. For the nine months ended March 31, 2012 and 2011 the decrease in the depletion was a result of reserve additions in the fourth quarter of fiscal 2011 at Senlac.

The depletion on petroleum and natural gas properties is booked on a quarterly basis. For the quarter ended March 31, 2012, $632.5 million in oil sands properties (STP-McKay Phase 1) were excluded from the depletion calculation and $128.0 million of future development costs were added, based on proved plus probable reserves. Exploration and evaluation assets ("E&E") are not depleted.

Foreign Exchange

	Three Months Ended March 31,			Nine Months Ended March 31,		
($ thousands except for per boe)	**2012**	2011	Change	**2012**	2011	Change
Foreign Exchange (gain) loss	**($2,503)**	($673)	272%	**$1,524**	($673)	-

For the three and nine months ended March 31, 2012, the Company had a foreign exchange gain of $2.5 million and a loss of $1.5 million, respectively. The foreign exchange gain or loss is the result of Southern Pacific completing a U.S. term loan facility during the prior year and the resulting changes in the Canadian dollar compared to the U.S. dollar. The U.S. debt and resulting cash balance has been re-valued into Canadian dollars at each reporting period. The change in the Canadian and U.S. foreign currency exchange rate and its resulting impact on the cash and debt balances being stated in Canadian dollars is recorded as a foreign exchange gain or loss.

For the three months ended March 31, 2012 the foreign exchange gain, primarily related to the U.S. debt, was the result of a strengthening Canadian dollar from $1.017 CAD/USD at December 31, 2011 to $0.999 CAN/USD at March 31, 2012. For the nine months ended March 31, 2012 the foreign exchange loss, also related to the U.S. debt, was largely attributable to a weakening Canadian dollar which moved from $0.964 CAN/USD at June 30, 2011 to $0.999 CAN/USD at March 31, 2012.

Stock-Based Compensation

($ thousands except for per boe)	Three Months Ended March 31, 2012	2011	Change	Nine Months Ended March 31, 2012	2011	Change
Stock-based compensation	**994**	472	111%	**2,856**	2,054	39%
Per boe	**$2.63**	$1.43	84%	**$2.79**	$1.85	51%

Stock-based compensation costs recognize the non-cash fair value of stock options issued to directors, officers and employees of Southern Pacific. The estimated fair value of the stock options awarded is calculated using the Black-Scholes option pricing model. The value of the award is then recognized as an expense over the period from grant date to the date of vesting of the award.

During the quarter and nine months ended March 31, 2012 stock-based compensation was $1.0 million, and $2.9 million compared to $0.5 million and $2.1 million for the same periods in 2011. The increase over the prior year is the result of new stock options being issued as personnel are hired to complete and operate the STP-McKay Phase 1 project.

Income Taxes

Southern Pacific recorded a $3.6 million and a $6.2 million deferred tax expense for the quarter and nine months ended March 31, 2012 compared to a $1.6 million recovery and $0.4 million deferred tax expense for the comparative quarter and nine months ended March 31, 2011.

The Company estimates it has approximately $665.0 million in tax pools before the deferred partnership income allocation as at March 31, 2012. Deferred partnership income is estimated to be $39.3 million, which would reduce the tax pools to $625.7 million. Both balances include $193.7 million in non-capital tax losses which expire over time from 2014 to 2031. Southern Pacific is not currently taxable and does not expect to pay income taxes in fiscal 2012.

Net Income

Southern Pacific recorded net income of $11.6 million, or $0.03 per share, for the quarter ended March 31, 2012, compared to net income of $0.1 million, or $0.00 per share, for same quarter in 2011. For the nine months ended March 31, 2012 the Company recorded net income of $11.1 million, or $0.03 per share, which is comparable to the net income of $7.4 million, or $0.02 per share, in the prior period.

FUNDS FROM OPERATIONS

($ thousands except per boe and per share)	Three Months Ended March 31, 2012	2011	Change	Nine Months Ended March 31, 2012	2011	Change
Funds from operations	**16,502**	9,322	77%	**38,425**	33,930	13%
Funds from operations per boe	**$43.64**	$28.27	54%	**$37.48**	$30.56	23%
Funds from operations - basic	**$0.05**	$0.03	67%	**$0.11**	$0.10	10%
Funds from operations - diluted	**$0.05**	$0.03	67%	**$0.11**	$0.10	10%

Funds from operations were $16.5 million for the quarter and $38.4 million for the nine months ended March 31, 2012, which is higher than the $9.3 million for the quarter and $33.9 million for the nine months ended March 31, 2011. The increase is attributable to higher commodity prices, lower operating costs, particularly for the quarter, offset by slightly higher royalties.

CAPITAL EXPENDITURES

The capital expenditures made on exploration and evaluation assets ("E&E") and property, plant and equipment ("PP&E") by Southern Pacific for the three and nine months ended March 31, 2012 and 2011 are summarized in the following table:

	Three Months Ended March 31,		Nine Months Ended March 31,	
($ thousands)	**2012**	2011	**2012**	2011
McKay – Phase 1 and 2	**$74,503**	$92,727	**$260,794**	$145,649
Senlac	**3,108**	2,716	**20,608**	10,991
Red Earth	**153**	40	**2,654**	149
Other Exploration	**44**	57	**101**	194
Corporate	**385**	506	**1,020**	967
Conventional	**(76)**	50	**(2,185)**	260
Acquisition	**-**	-	**-**	19,168
Total	**$78,117**	$96,096	**$282,992**	$177,378

For the quarter and nine months ended March 31, 2012 the Company incurred $78.1 million and $283.0 million in capital expenditures. For STP-McKay Phase 1 and 2 the total expenditures for the quarter and nine months ended March 31, 2012 of $74.5 million and $260.8 million include capitalized interest of $12.2 million and $36.4 million respectively. The increase in McKay capital expenditures is related to the building of the SAGD facility which commenced in September of 2010. Senlac capital costs are up over the prior year quarter due to the drilling and completion of the Phase J well pairs. The Red Earth project was acquired as part of the North Peace acquisition on November 23, 2010. As such, limited activity occurred for the quarter and nine months ended March 31, 2011. Post this period, the capital expenditures increased as the Company tested the wells up to the end of December 2011. Corporate capital increased over the prior year for the nine months ended March 31, 2012 as the company incurred costs related to leasehold improvements and increased capitalized geological and geophysical costs. Conventional assets were sold in July 2011, resulting in a total capital reduction of $2.2 million for the nine months ended March 31, 2012. The acquisition capital of $19.2 million is the result of the North Peace acquisition that occurred in the second quarter of 2011.

Capital additions are recorded in both E&E assets and PP&E on the financial statements. The E&E assets, in the above additions, include STP-McKay Phase 2, Red Earth and other oil sands exploration lands. These projects are included in E&E as they have not yet obtained technical feasibility and commercial viability. PP&E assets include STP-McKay Phase 1, STP-Senlac and other corporate capital expenditures.

For the three months ended March 31, 2012 economic viability and technical feasibility was established in regards to a portion of the STP-McKay Phase 2 assets. As a result, related costs of $66.9 million were transferred from E&E to PP&E.

LIQUIDITY AND CAPITAL RESOURCES

As at March 31, 2012 Southern Pacific had working capital of $32.1 million. The Company also has an undrawn $30.0 million demand revolving operating credit facility with a syndicate of banks. The term of the credit facility is three years and extendible at the lenders' discretion. The credit facility is guaranteed by all of the Company's subsidiaries and secured by a security interest in all of the existing and future assets of the Company and its subsidiaries. The security interest has first priority over all other creditors.

($ thousands)	March 31, 2012
Bank lines available	**$30,000**
Working capital	**32,145**
Capital resources available	**$62,145**

Southern Pacific believes it has sufficient capital to complete its STP-McKay Phase 1 project, fund budgeted capital expenditures at STP-Senlac, and execute other project developments at McKay from its available capital resources of $62.1 million and budgeted funds from operations over the next 12 months.

COMMITMENTS

Risk Management Activities

Oil and gas producers are exposed to fluctuations in commodity prices that are beyond the control of management. To protect cash flow for future capital programs, Southern Pacific has entered into the following commodity contracts to reduce the price risk of oil prices and natural gas purchases as of May 14, 2012:

Type	Contract Term	Volume	Price
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	900 bbl/day	US$85.00-$115.75
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	500 bbl/day	US$90.00-$110.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	700 bbl/day	US$90.00-$115.05
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.10
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.12
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	700 bbl/day	US$90.00-$100.00
Oil collar (WTI)	Jan 1, 2013 to Dec 31, 2012	1,000 bbl/day	US$90.00-$114.50
Differential SWAP (WTI)	Jan 1, 2012 to Dec 31, 2012	1,000 bbl/day	WTI-US$17.25
Differential SWAP (WTI)	Jan 1, 2012 to Dec 31, 2012	500 bbl/day	WTI-US$16.95
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.00 CAD/USD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.0290 CAD/USD

Fixed Price Contracts

As of May 14, 2012 the Company committed to the following fixed price gas purchase contracts. The contracts are entered into to reduce the risk of gas price uncertainty, as gas is a significant input cost for the Senlac operations.

Type	Contract Term	Volume	Price
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.14
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.00
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$3.93
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	500 gj/day	$3.86
Natural gas fixed purchase (AECO)	July 1, 2012 to Dec 31, 2012	2,000 gj/day	$2.96
Natural gas fixed purchase (AECO)	July 1, 2012 to Dec 31, 2012	1,000 gj/day	$2.75

Leases

At March 31, 2012 the Company is committed to annual lease payments under the terms of a lease for its head office space and equipment:

($ thousands)	Amount
2012	$138
2013	489
2014	496
2015	360
2016	87
Thereafter	65
Total	$1,207

Capital

At December 31, 2011, as part of normal operations relating to the construction of the STP-McKay Phase 1 SAGD project, the Company entered into a total of $28.1 million in capital commitments to be paid over the next year.

Principal Payments

At March 31, 2012, the Company's required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

	Term loan	Convertible debentures	**Total**
2012	$687	-	**$687**
2013	2,748	-	**2,748**
2014	2,748	-	**2,748**
2015	2,748	-	**2,748**
2016	262,389	172,500	**434,889**
Total	$271,320	$172,500	**$443,820**

OFF BALANCE SHEET ARRANGEMENTS

Southern Pacific has not entered into any off balance sheet arrangements at March 31, 2012.

TRANSACTIONS WITH RELATED PARTIES

During the quarter and nine months ended March 31, 2012 the Company incurred legal costs of $0.1 million (2011 - $0.2 million) and $0.4 million (2011 - $0.4 million) with a law firm in which the corporate secretary is a partner. The legal costs incurred were in the normal course of operations and were based on the exchange value of the service provided, which approximates those amounts of consideration with third parties. Of the legal services provided, $nil were included in accounts payable at March 31, 2012 (June 30, 2011 - $nil).

OUTSTANDING SECURITIES

Common Shares, Options and Warrants

There were 1.2 million and 2.0 million common shares issued during the quarter and nine months ended March 31, 2012 respectively, at a weighted average exercise price of $0.78 and $0.67 per share respectively, from the exercise of stock options. In addition, 0.2 million warrants were exercised in the three and nine months ending March 31, 2012 at a weighted average exercise price of $1.01.

As at March 31, 2012, 23.5 million stock options were outstanding with an average exercise price of $1.30 and nil warrants were outstanding. At May 14, 2012, the Company has 341.3 million common shares outstanding, 24.3 million stock options outstanding and nil warrants outstanding.

SELECTED QUARTERLY INFORMATION

The following information summarizes the financial results of the Company for each quarter during the past two fiscal years:

($ thousands except for per boe)	03/31/12 (1)	12/31/11 (1)	09/30/11 (1)	06/30/11 (1)	03/31/11 (1)	12/31/10 (1)	09/30/10 (1)	06/30/10 (2)
Production (boe/d)	4,156	3,249	3,784	4,915	3,664	4,359	4,123	4,191
Oil and gas revenue	$24,399	$21,994	$20,769	$30,721	$18,791	$23,514	$20,701	$20,673
Combined average price ($/boe)	$64.52	$73.54	$59.65	$68.68	$56.98	$58.63	$54.58	$54.21
Royalties ($/boe)	$11.48	$10.86	$10.38	$12.73	$9.93	$11.31	$8.85	$8.18
Operating costs ($/boe)	$8.63	$11.26	$12.02	$8.91	$11.59	$10.59	$9.56	$9.67
Operating netback ($/boe)	$44.41	$51.42	$37.25	$47.04	$35.46	$36.73	$36.17	$36.36
G&A expense ($/boe)	$6.60	$12.55	$6.33	$7.12	$7.96	$6.14	$3.30	$3.98
Funds from operations	$16,502	$11,248	$10,675	$17,942	$9,322	$12,268	$12,340	$11,837
Per share - basic	$0.05	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04	$0.04
- diluted	$0.05	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04	$0.04
Net income (loss)	$11,553	$224	($697)	$7,474	$111	$5,506	$1,795	($1,312)
Per share - basic	$0.03	($0.00)	($0.00)	$0.02	$0.00	$0.02	$0.01	($0.00)
- diluted	$0.03	($0.00)	($0.00)	$0.02	$0.00	$0.02	$0.01	($0.00)
Capital expenditures	$78,117	$98,972	$105,903	$104,874	$96,096	$74,203	$7,079	$42,380

(1) Quarterly information is presented in accordance with IFRS which the company adopted on June 30, 2010 and applied retroactively.
(2) Quarterly information is presented in accordance with Canadian GAAP.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's

Chief Executive Officer and Chief Financial Officer by others, particularly during the periods in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. All control systems, by their nature, have inherent limitations and, therefore, the Company's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that the objectives of the control systems are met.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company has, as its requirement under National Instrument 52-109, to evaluate design effectiveness and then test the effectiveness of its control environment during fiscal 2012, and has retained expert advisors to assist in the process. Based on this process, as of March 31, 2012 the CEO and CFO had concluded that its internal control over financial reporting is effective.

The Company's internal controls over financial reporting may not prevent or detect all errors, misstatements and fraud. The design of internal controls must also take into account resource constraints. A control system, including the Company's internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

NEW ACCOUNTING POLICIES

International Financial Reporting Standards ("IFRS")

In 2008, the CICA Accounting Standards Board confirmed that IFRS will replace Canadian GAAP for fiscal years beginning on or after January 1, 2011 for publicly accountable enterprises. The Company's IFRS transition date was July 1, 2011. Comparative information for periods from July 1, 2010 onwards has been restated in accordance with IFRS.

Transition to IFRS

With the conversion to IFRS, the Company completed an assessment of the impact of IFRS on internal controls over financial reporting ("ICOFR"). Based on this assessment no significant changes to the controls and procedures were required.

An assessment of the Company's infrastructure was also completed, primarily information technology and data systems. The assessment indicated that significant changes were necessary. As a result, the Company completed the transition to update its systems with a full conversion in the second quarter of fiscal 2011.

First-time Adoption of IFRS

IFRS 1 "First Time Adoption of IFRS" provides certain optional exemptions for entities adopting IFRS for the first time. The most significant elections taken are outlined here. IFRS 1 allows an entity that used full cost accounting under Canadian GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under Canadian GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under Canadian GAAP for those assets to the underlying assets pro rata using reserve

volumes or reserve values as of that date. The Company exercised this exemption and allocated the assets using proved and probable reserve volumes.

IFRS 2 "Share-based Payments" whereby stock options that vested prior to January 1, 2010 are not required to be retrospectively restated. Therefore, IFRS 2 requirements apply only to those options that were unvested at the transition date. Southern Pacific elected to apply this exemption.

In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets the Company has elected to re-measure the decommissioning liabilities in accordance with the IAS 37 standard. As allowed under IFRS 1, any difference between the IAS 37 amount and the carrying amount of the liabilities under Canadian GAAP at the date of transition was booked directly to retained earnings.

IFRS 1 does not allow hindsight to be used to create or revise previous estimates. Accordingly, the Company did not revise estimates previously made under Canadian GAAP, except where necessary, to reflect a change resulting from differences in accounting policy. A summary of all IFRS optional exceptions applied is outlined in Note 16 of the consolidated financial statements.

Significant IFRS impacts on financial reporting

The IFRS accounting policies are set forth in Note 3 of the unaudited consolidated financial statements for the period ended March 31, 2012. A detailed explanation of how the transition from Canadian GAAP to IFRS has impacted the Company's financial position, financial performance and cash flow, including the required reconciliations under IFRS 1, is also presented in the unaudited consolidated financial statements under Note 16.

The most significant impacts of IFRS upon conversion were within the areas of exploration and evaluation assets, depletion and depreciation expense, decommissioning liabilities, deferred income tax, share-based compensation, impairment and convertible debentures.

Exploration & Evaluation assets ("E&E")

IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas assets and has identified two significant differences in the accounting for assets under IFRS, one the treatment of pre-exploration costs and two the segregation of exploration and evaluation costs from property plant and equipment ("PP&E").

Pre-exploration costs are costs incurred before the Company obtains the legal right to explore an area. Under Canadian GAAP these costs were capitalized, while under IFRS, these costs must be expensed.

During the exploration and evaluation phase, the Company capitalized costs incurred for these projects under Canadian GAAP as part of PP&E. The Company, under IFRS, will capitalize these costs as exploration and evaluation assets until technical feasibility and commercial viability of the project has been determined. If not, the costs must be expensed to the statement of comprehensive income. If technical feasibility and commercial viability is obtained then the assets will be transferred to PP&E assets.

As a result of these differences $172.5 million in assets were transferred from PP&E to exploration and evaluation assets at July 1, 2010. Similarly the company reclassified $153.2 at March 31, 2011.

Depletion and depreciation expense

Canadian GAAP mandated that oil and gas properties were to be depleted on a unit of production method using remaining proved reserves on a cost center basis that was defined as a country.

IFRS requires the depreciation method to best reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. IFRS requires that depletion be calculated on a significant component basis. Under IFRS the Company elected to deplete its oil and gas properties using the unit of production method but on a proved plus probable reserve basis. Assets, including STP-McKay Phase 1, that are yet to be brought into use or are not in the location and condition necessary for the assets to be capable of operating in the manner intended by management, are excluded from the depletion calculation.

The above changes resulted in a decrease to depletion expense and an increase in the carrying value of property, plant and equipment. This amount was $4.5 million at March 31, 2011.

Decommissioning liability

IAS 37 "Provisions, Contingent Liabilities and Contingent Assets", allows that the decommissioning liability be discounted using a risk free rate of 3.08% as at the transition date of July 1, 2010. Canadian GAAP required a credit-adjusted risk free rate which was substantially higher at 8.0%. As a result of using the lower risk free discount rate there was an increase of $3.7 million to the decommissioning liability with a corresponding increase to the Company's deficit at July 1, 2010. At March 31, 2011 a rate of 3.35% was used with an increase to the decommissioning liability of $3.9 million.

IAS 37 also requires that the timing and amount of future expenditures are reviewed regularly, together with the interest rate used in discounting the cash flows and the carrying amount of the provision is adjusted accordingly. Under Canadian GAAP, a provision previously recognized was not revised for subsequent changes in the interest rates.

Deferred income tax

Under Canadian GAAP, proceeds from the issuance of flow-through shares are recorded at their total value which typically includes a premium over the trading value of common shares. The tax basis of assets related to expenditures incurred to satisfy flow-through share obligations is reduced when the renunciation of the related tax pools occurs which then increased the deferred income tax liability and reduced share capital. Under IFRS, the premium over the fair market value of "regular" common shares is not recorded to share capital but set up as a deferred obligation upon issuance of flow-through shares. As the tax deductions associated with the flow-through expenditures are renounced, a deferred income tax liability is estimated based on the amount of deferred income taxes now payable by the Company. As the deferred income tax liability is recorded, it is offset to the deferred obligation with any differences recognized in profit or loss. There is no impact to share capital on renunciation of flow-through shares.

The above accounting policy change, upon transition to IFRS, increased the share capital of the Company by approximately $2.0 million at July 1, 2010. This policy did not impact the financial statements as at and for the periods ended June 30, 2011.

Share issue costs were treated as a temporary difference under Canadian GAAP but under IFRS these are treated as an adjustment to share capital when the tax rate changes. At transition date this adjustment was $0.1 million.

The convertible debentures liability and equity portions were adjusted for the value of a redemption option. The deferred tax impact on the equity component was a permanent tax difference under previous GAAP, however, under IFRS this is a temporary difference. This adjustment has reduced the equity portion of the convertible debenture and increased deferred tax by $9.3 million for the year ended June 30, 2011. This change also reduced the deferred income tax expense as at June 30, 2011 by $0.7 million for the period ended June 30, 2011. The expense

was reduced because the temporary difference of $9.3 million is reversed over time, as the debt portion of the convertible debenture is accreted.

Deferred income tax calculated according to IFRS is substantially similar to Canadian GAAP and arises from the differences in the accounting and tax bases of assets and liabilities. Where balances have changed due to IFRS differences, the amount of deferred income tax liability will be impacted.

Under Canadian GAAP, deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

Under Canadian GAAP, Saskatchewan resource payments were classified as a tax however under IFRS they are now classified as a royalty and netted to petroleum revenue.

Share based compensation

Under Canadian GAAP, the company recognized an expense related to share-based payments on a straight-line basis and did not include an estimate of forfeitures. Under IFRS the company is required to recognize the expense over the individual vesting periods for the graded vesting awards and to estimate a forfeiture rate. At transition date this resulted in a $0.2 million decrease to contributed surplus and an increase to retained earnings. At March 31, 2011 the decrease to contributed surplus was $0.4 million.

Long term debt and equity component of convertible debentures

Under IFRS and previous GAAP, the convertible debentures are treated as a compound financial instrument. However, under IFRS, the value of the embedded call option is considered a part of the liability component and as a result, the equity portion of the convertible debenture was reduced by $4.5 million with a corresponding increase to long-term debt. In addition, under IFRS, the equity component was adjusted for deferred taxes, resulting in a decrease of the equity component of convertible debentures of $14.5 million. The effective interest rate calculation was also adjusted to reflect the IFRS changes above.

CRITICAL ACCOUNTING ESTIMATES

Oil and Gas Reserves

The process of estimating reserves and contingent resources is complex. It requires significant judgments and decisions based on geological, geophysical, engineering and economic data. Reserve and contingent resource estimates are based on current production forecasts, prices and economic conditions. These estimates may change substantially as additional data from ongoing development and production activities become available and as economic conditions impact oil and gas prices and costs. Southern Pacific's properties are evaluated annually by independent petroleum engineering consultants.

Exploration and Evaluation Assets

Exploration and evaluation costs associated with the Company's oil sands activities are capitalized as either tangible or intangible exploration and evaluation assets, according to the nature of the assets acquired. These costs are accumulated in E&E pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when reserves are determined to exist. The determination of reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairment of Property and Equipment

Intangible exploration and evaluation assets are assessed for impairment when they are reclassified into PP&E, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The carrying value of the Company's PP&E assets are reviewed for indication of impairment at each reporting date. The PP&E assets are aggregated into cash-generating units ("CGU's") for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. If impairment is indicated, the CGU is written down to the greater of the value in use or fair value less costs to sell. Each calculation is dependent on a number of estimates including reserves, production rates, prices, future costs and other relevant assumptions. As a result, these estimates are subject to significant management judgment.

Withheld Costs

Certain costs included in major project developments related to the Company's oil sands assets classified in PP&E may be excluded from costs subject to depletion. These costs are excluded until the assets are determined to be operating in the manner intended by management which requires judgment.

Decommissioning Obligations

When Southern Pacific has drilled core holes, it has properly abandoned them within the drilling program and therefore, no decommissioning obligation has been booked on its core hole program. The Company is required to provide for future removal and restoration costs on its oil and gas assets. Southern Pacific estimated these costs in accordance with existing laws, contracts or other policies. The fair value of the liability for the decommissioning obligations is recorded in the period in which it is to be incurred and discounted to its present value using a risk free rate. The offset to the liability is recorded in the carrying amount of property and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded and any difference is booked to profit or loss.

Depletion Expense

Depletion and depreciation of petroleum and natural gas properties, including the Company's oil sands facilities, are calculated using the unit-of-production method based upon the production volumes and/or the facilities productive capacity, before royalties, in relation to the estimated total proved and probable petroleum and natural gas reserves as estimated by independent engineers. In determining costs subject to depletion, Southern Pacific also includes estimated future costs to be incurred in developing proved and probable reserves. The determination of future development costs, reserves, and productive capacity are all subject to significant judgments and estimates.

Stock-Based Compensation

The Company uses the fair value method for valuing stock option grants. The fair value of each option is estimated on the date of the grant using the Black-Scholes option pricing model. This model requires Southern Pacific's management to make estimates and assumptions for the expected volatility, risk-free rate and forfeiture rate. A zero dividend is used as the Company does not issue dividends. The volatility is a calculation based on the past trading history of the Company's shares, the risk-free rate is obtained from the Bank of Canada and the forfeiture rate

is based on past activity. An increase in dividends or forfeiture rate would decrease the option expense and an increase in the volatility or risk-free rate would increase the option expense.

Income Tax

The determination of the Company's income tax and other liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual liability may differ from that estimated and recorded by management.

Risk Management Contracts

The Company may utilize risk management contracts to manage its currency and interest rate exposures. The financial instruments are not issued for trading or speculative purposes. The fair values of risk management contracts are estimated at the balance sheet date based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecasted interest rates, foreign exchange rates and commodity prices expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the risk management contracts.

Cash Generating Units

Oil and natural gas assets are grouped into CGU's that have been identified as being the smallest identifiable group of assets that generate cash flows, that are independent of cash flows of other assets or groups of assets. The determination of these CGU's was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

BOE PRESENTATION

The use of barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 barrel is based on an energy equivalent conversion method primarily applicable at the burner tip and is not intended to represent a value equivalency at the wellhead.

NOTE REGARDING NON-IFRS MEASURES

This MD&A includes references to certain financial measures, as described below, which do not have standardized meanings prescribed by IFRS. Because these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The Company uses these measures to evaluate its performance. Investors are cautioned that these non-IFRS measures should not be construed as an alternative to the measures calculated in accordance with IFRS as, given their non-standardized meanings, they are unlikely to be comparable to similar measures presented by other issuers. The term "operating netback" is defined as petroleum and natural gas sales less royalties and less operating and transportation costs. The term "funds from (used in) operations" is defined as the cash flow from operating activities before the change in non-cash working capital and abandonment expenditures and should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net income (loss) as determined in accordance with IFRS as an indicator of performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. A summary of this reconciliation is as follows:

($ thousands)	Three Months Ended March 31, **2012**	2011	Nine Months Ended March 31, **2012**	2011
Cash provided by operations	**$14,705**	$25,053	**$37,686**	$38,456
Change in non-cash working capital	**1,797**	(15,731)	**739**	(4,578)
Decommissioning expenditures	**-**	-	**-**	52
Funds from operations	**$16,502**	$9,322	**$38,425**	$33,930

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A may constitute forward-looking statements. These statements relate to future events or Southern Pacific's future performance. All statements, other than statements of historical fact, may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "plan," "continue," "estimate," "expect," "may," "will," "project," "predict," "propose," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Forward-looking statements included in this MD&A should not be unduly relied upon by investors as actual results may vary. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- capital expenditure programs;
- development of resources;
- treatment under governmental regulatory and taxation regimes;
- expectations regarding the Company's ability to raise capital;
- expenditures to be made by the Company to meet certain work commitments; and,
- work plans to be conducted by the Company.

With respect to the forward-looking statements listed above and contained in this MD&A, the Company has made assumptions regarding, among other things:

- the legislative and regulatory environment;
- the impact of increasing competition;
- unpredictable changes to the market prices for oil and natural gas;
- costs related to the development of the Company's oil and gas properties (that they will remain consistent with historical experience);
- the anticipated results of exploration activities; and,
- the Company's ability to obtain additional financing on satisfactory terms.

Southern Pacific's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

- volatility in the market prices for oil and natural gas;
- uncertainties associated with estimating resources;
- geological, technical, drilling and processing problems;
- liabilities and risks, including environmental liabilities and risks, inherent in oil and natural gas operations;

- fluctuations in currency and interest rates;
- incorrect assessments of the value of acquisitions;
- unanticipated results of exploration activities;
- competition for, among other things, capital, reserves, undeveloped lands and skilled personnel; and,
- unpredictable weather conditions.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth above. These factors include the risks discussed in the Company's Annual Information Form for the year ended June 30, 2011, which include, without limitation, the inherent risks involved in a developmental stage oil sands extraction enterprise.

Southern Pacific faces uncertainties, including those associated with resource definition, the timeline to production of STP-McKay Phase 1, the possibility of cost overruns or unanticipated costs and expenses, regulatory approvals, changes to royalty regimes, fluctuating commodity prices and currency exchange rates and the ability to access sufficient capital from external sources to finance future development. As a consequence, actual results may differ, and may differ materially, from those anticipated in the forward-looking statements. The reader is cautioned not to place undue reliance on these forward-looking statements as there can be no assurance that such plans, intentions or expectations upon which they are based will occur. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this MD&A are made as of the date of this MD&A and state no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise, expect as required by applicable securities laws.

RISK FACTORS

The Company's business consists of the exploration and development of oil and gas properties in Western Canada. There are a number of inherent risks associated with the exploration for and development and production of oil and gas reserves. Many of these risks are beyond the control of the Company. These risk factors are described in the Company's Annual Information Form filed on SEDAR on September 21, 2011 at www.sedar.com and available on Southern Pacific's website at www.shpacific.com. Please refer to this document for more information.

SOUTHERN PACIFIC
RESOURCE CORP.

Condensed Interim Consolidated Financial Statements for the Three and nine months ended March 31, 2012 and 2011 (Unaudited)

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statements of Financial Position
Stated in thousands of Canadian dollars (Unaudited)

	March 31, 2012	June 30, 2011
Assets		
Current assets		
Cash and cash equivalents (notes 4 and 7)	**$ 82,934**	$ 322,927
Trade and other accounts receivable	**12,244**	13,091
Prepaid expenses and deposits	**1,170**	1,157
Risk management contracts (note 12)	**2,753**	570
	99,101	337,745
Non-current assets		
Exploration and evaluation assets (note 5)	**94,242**	155,562
Property, plant and equipment (note 6)	**726,507**	385,580
	$ 919,850	$ 878,887
Liabilities and Shareholders' Equity		
Current liabilities		
Trade and other accounts payable	**$ 64,208**	$ 75,574
Current portion of long term debt (note 7)	**2,748**	2,652
	66,956	78,226
Non-current liabilities		
Long term debt (note 7)	**393,069**	379,148
Decommissioning liability (note 8)	**37,628**	22,127
Deferred income tax liability	**52,356**	46,197
	550,009	525,698
Shareholders' equity		
Share capital (note 9)	**309,239**	306,499
Equity component of convertible debentures (note 7)	**25,284**	25,284
Contributed surplus (note 10)	**27,225**	24,393
Retained earnings (deficit)	**8,093**	(2,987)
	369,841	353,189
	$ 919,850	$ 878,887

Commitments (note 13)

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statements of Comprehensive Income
Stated in thousands of Canadian dollars except per share amounts (Unaudited)

	Three months ended, March 31		Nine months ended, March 31	
	2012	2011	**2012**	2011
Revenues and Other Income				
Petroleum revenue, net of royalties (note 14)	**$ 21,598**	$15,665	**$ 57,499**	$ 51,987
Gain (loss) on risk management contracts (note 12)	**5,215**	(4,533)	**3,315**	(5,511)
	26,813	11,132	**60,814**	46,476
Expenses				
Operating	**3,262**	3,821	**10,814**	11,696
Exploration and evaluation	**-**	10	-	353
General and administrative	**2,495**	2,626	**8,452**	6,340
Finance (note 15)	**169**	58	**494**	232
Stock based compensation	**994**	472	**2,856**	2,054
Foreign exchange (gain) loss	**(2,503)**	(673)	**1,524**	(673)
Depletion and depreciation	**7,258**	6,317	**19,432**	22,249
	11,675	12,631	**43,572**	42,251
Other				
Gain on acquisition	**-**	-	**-**	3,585
Income (loss) before income taxes	**15,138**	(1,499)	**17,242**	7,810
Deferred income tax expense (recovery)	**3,585**	(1,610)	**6,162**	397
Net income and comprehensive income for the period	**11,553**	111	**11,080**	7,413
Earnings per share - basic and diluted	**$0.03**	$0.00	**$0.03**	$0.02
Weighted average number of shares outstanding:				
Basic	**340,512**	337,581	**339,859**	329,644
Diluted	**348,000**	337,581	**346,294**	336,561

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statements of Changes in Shareholders' Equity
Stated in thousands of Canadian dollars (Unaudited)

Nine months ended March 31,	**2012**	2011
Share Capital (note 9)		
Balance, July 1	**$ 306,499**	$ 283,603
Exercise of options	**2,580**	1,558
Exercise of warrants	**160**	
Share issue costs	**-**	(32)
Acquisition of North Peace	**-**	20,153
Balance, March 31	**309,239**	305,282
Contributed Surplus (note 10)		
Balance, July 1	**24,393**	23,064
Options exercised	**(1,248)**	(840)
Stock-based compensation	**4,080**	2,054
Balance, March 31	**27,225**	24,278
Retained Earnings (Deficit)		
Balance, July 1	**(2,987)**	(17,874)
Net income for the period	**11,080**	7,413
Balance, March 31	**$ 8,093**	$ (10,461)

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statements of Cash Flows
Stated in thousands of Canadian dollars (Unaudited)

	Three months ended March 31,		Nine months ended March 31,	
	2012	2011	**2012**	2011
Cash provided by (used in)				
Operating activities:				
Net income	**$ 11,553**	$ 111	**$ 11,080**	$ 7,413
Adjustments for:				
Depletion and depreciation	**7,258**	6,317	**19,432**	22,249
Finance expense (note 15)	**1**	24	**56**	49
Exploration and evaluation	**-**	10	**-**	353
Unrealized (gain) loss on foreign exchange (note 12)	**(2,412)**	(673)	**1,022**	(673)
Unrealized (gain) loss on risk management contracts (note 12)	**(4,477)**	4,671	**(2,183)**	5,673
Stock based compensation	**994**	472	**2,856**	2,054
Deferred taxes	**3,585**	(1,610)	**6,162**	397
Gain on acquisition	**-**	-	**-**	(3,585)
	16,502	9,322	**38,425**	33,930
Change in non-cash operating working capital	**(1,797)**	15,731	**(739)**	4,578
Decommissioning expenditures (note 8)	**-**	-	**-**	(52)
	14,705	25,053	**37,686**	38,456
Financing activities:				
Issuance of common shares, net of share issuance costs (note 9)	**1,107**	532	**1,492**	686
Issuance of long term debt, net of costs	**-**	421,893	**-**	421,893
Repayment of long-term debt	**(687)**	(668)	**(2,097)**	(668)
	420	421,757	**(605)**	421,911
Investing activities:				
Exploration and evaluation expenditures (note 5)	**(340)**	(143)	**(5,223)**	(143)
Property plant and equipment expenditures (note 6)	**(75,110)**	(94,509)	**(272,057)**	(156,665)
Petroleum and natural gas dispositions	**-**	-	**1,786**	72
Net change in non-cash investing working capital	**(18,655)**	11,892	**(10,117)**	52,757
	(94,105)	(82,760)	**(285,611)**	(103,979)
Net decrease in cash and cash equivalents	**(78,980)**	364,050	**(248,530)**	356,388
Foreign exchange (loss) gain on cash balances (note 12)	**(2,461)**	(5,362)	**8,537**	(5,362)
Cash and cash equivalents, beginning of period	**164,375**	55,843	**322,927**	63,505
Cash and cash equivalents, end of period	**$82,934**	$ 414,531	**$ 82,934**	$414,531
Supplementary cash flow information				
Finance costs paid and capitalized (note 6)	**$ 9,913**	$9,216	**$29,801**	$9,216

See accompanying notes to the financial statements.

1. Incorporation and nature of operations:

Southern Pacific Resource Corp., its subsidiaries; Southern Pacific Energy Ltd., Southern Pacific Resource Partnership, and 1614789 Alberta Ltd. (collectively the "Company") were either incorporated under the Business Corporation Act of Alberta or organized under the partnership laws of the Province of Alberta. The Company is a publicly traded company headquartered at 1700, 205 5th Avenue SW, Calgary, Alberta, Canada and its shares trade on the Toronto Stock Exchange "TSX" under the symbol "STP".

The Company's operations are comprised of production of heavy oil from a thermal project in Saskatchewan known as STP-Senlac, development of an in-situ project in Alberta known as STP-McKay Phase 1 for the production of bitumen, and the exploration and development of other in-situ oilsands properties located in northern Alberta, Canada. The Company has filed an application for an expansion in-situ project in McKay known as STP-McKay Phase 2.

2. Basis of preparation:

(a) Statement of Compliance

The March 31, 2012 condensed interim consolidated financial statements (the "financial statements") are prepared under International Financial Reporting Standards ("IFRS"). The Company's transition date to IFRS was July 1, 2010 and results for each of the periods from July 1, 2010 to June 30, 2011 have been restated from the previous Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS. These restated comparative financial statements are presented as comparative figures for this and future quarterly and annual financial statements. The transition to IFRS resulted in changes to the Company's accounting policies and these are disclosed in Note 16 along with reconciliations of the statements under previous Canadian GAAP to their IFRS values. These financial statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with International Accounting Standard (IAS) 34, "Interim Financial Reporting".

The policies applied in these financial statements are based on IFRS issued and outstanding as of May 14, 2012, the date the Audit Committee approved the financial statements. Any subsequent changes to IFRS that take effect in the Company's annual financial statements for the year ending June 30, 2012 could result in restatement of these financial statements, including the transitional adjustments recognized on the change-over to IFRS.

These financial statements do not include all the necessary annual disclosures in accordance with IFRS. Accordingly, the financial statements should be read in conjunction with the Company's Canadian GAAP annual financial statements for the year ended June 30, 2011 and the IFRS financial statements for the quarter ended September 30, 2011.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis except for the revaluation of derivative instruments to fair value.

(c) Functional and presentation currency

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

(d) Use of estimates and judgment

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur.

Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property, plant and equipment and the related accrued liability. In addition, judgments regarding the timing of when major development projects are ready for their planned use affect the amounts recorded in property, plant and equipment or intangible assets.

Amounts recorded for depletion and obligations, and impairment calculations and amounts used in the determination of future taxes are based on estimates of petroleum, natural gas and bitumen reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs and the related future cash flows are subject to measurement uncertainty.

Amounts recorded for depreciation of major facilities and equipment and pipeline transportation equipment are based on management's best estimate of their useful lives. Accordingly, those amounts are subject to measurement uncertainty.

Amounts recorded for decommissioning obligations are based on management's best estimate of expenditures required to settle the present obligation as well as changes in the discount rate. Accordingly, those amounts are subject to measurement uncertainty.

Amounts recorded for stock based compensation expense are based on management's best estimate of expected volatility of the Company's share price, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

The estimated fair value of the Company's financial assets and liabilities are determined based on valuation models where the significant inputs are based on available information for similar securities and information regarding the specific assets held, which may not be indicative of the value of the actual securities held by the Company. Accordingly, these amounts are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in which the Company operates are subject to change. Accordingly, income taxes are subject to measurement uncertainty.

Oil and natural gas assets are grouped into cash generating units (CGU's) that have been identified as being the smallest identifiable group of assets that generate cash flows, which are independent of cash flows of other assets or groups of assets. The determination of these CGU's was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

3. Significant accounting policies:

These financial statements follow the same accounting principles and methods of application as those disclosed in note 3 to the Company's September 30, 2011 interim consolidated financial statements.

(a) Recent accounting pronouncements issued but not yet effective:

The following standards have been issued but are not yet effective. They may result in future changes to accounting policies and other note disclosures. Each of these new standards is effective for annual fiscal periods beginning on or after January 1, 2013 with early adoption permitted.

IFRS 9 "Financial Instruments" – issued in November 2009 and revised in October 2010. Portions of this standard are still in the process of development and the standard will eventually replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9 introduces new requirements for classifying and measuring assets and liabilities. The full impact of the standard will not be known until the project is complete.

IFRS 10 "Consolidated Financial Statements" – issued in May 2011. This standard replaces the consolidation requirements in SIC-12 "Consolidation - Special Purpose Entities" and IAS 27 "Consolidated and Separate Financial Statements".

IFRS 11 "Joint Arrangements" – issued in May 2011. This standard replaces IAS 31 "Interests in Joint Ventures" and SIC-13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers".

IFRS 12 "Disclosure of Interests in Other Entities" – issued in May 2011. This is a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities.

IFRS 13 "Fair Value Measurement" – issued in May 2011. This standard applies to other IFRS that require fair value measurement and sets out a single IFRS framework for measuring fair value and also requires disclosures about fair value measurements.

The following existing standards have been amended:

IAS 1 "Presentation of Financial Statements" – This amendment provides guidance on the presentation of items contained in other comprehensive income (OCI) and their classification within OCI. This is required to be applied beginning on or after July 1, 2012 with earlier adoption permitted.

IAS 19 "Post Employment Benefits" – The amendment makes changes to the recognition and measurement of defined benefit pension expense and expands disclosure for all employee benefit plans. This is required to be applied as of January 1, 2013 with earlier adoption permitted.

Management is assessing the impact of these new standards and amendments but they are not expected to have a material impact on the Company's Consolidated Financial Statements.

4. Cash and cash equivalents:

Cash and cash equivalents are funds primarily intended for the STP-McKay Phase I project. As at March 31, 2012 and June 30, 2011, US$50 million is held in a separate collateral escrow account (note 7(b)).

5. Exploration and evaluation assets ("E&E"):

Balance at July 1, 2010	$172,546
Transferred to property, plant and equipment	(46,437)
Additions	29,760
Exploration and evaluation expense	(307)
Balance at June 30, 2011	$155,562
Additions	5,568
Transferred to property, plant and equipment	(66,888)
Balance at March 31, 2012	**$ 94,242**

Exploration and evaluation assets are comprised of undeveloped land and oil sands evaluation projects pending the determination of technical feasibility and commercial viability.

During the three and nine months ended March 31, 2012 the Company capitalized $0.2 million and $0.8 million (March 31, 2011 – $nil) of directly attributable expenses and $nil of interest and debt service costs (March 31, 2011 – $nil) relating to oil sands exploration and evaluation.

6. Property, plant and equipment (PP&E):

Cost	**Oil and gas properties**	**Corporate**	**Total**
Balance at July 1, 2010	$104,856	$568	$105,424
Transferred from E&E	46,437	-	46,437
Capital expenditures	251,670	1,129	252,799
Change in decommissioning liabilities	11,500	-	11,500
Balance at June 30, 2011	$414,463	$1,697	$416,160
Transferred from E&E	66,888	-	66,888
Capital expenditures	279,012	520	279,532
Change in decommissioning liabilities	15,725	-	15,725
Dispositions	(2,109)	-	(2,109)
Balance at March 31, 2012	**$773,979**	**$2,217**	**$ 776,196**
Accumulated depletion and depreciation			
Balance at July 1, 2010	$ -	$160	$160
Depletion and depreciation	30,152	268	30,420
Balance at June 30, 2011	$30,152	$428	$30,580
Depletion and depreciation	19,031	401	19,432
Dispositions	(323)	-	(323)
Balance at March 31, 2012	**$48,860**	**$829**	**$49,689**
Carrying Amounts			
As at July 1, 2010	$104,856	$408	$105,264
As at June 30, 2011	$384,311	$1,269	$385,580
As at March 31, 2012	**$725,119**	**$1,388**	**$726,507**

During the three and nine months ended March 31, 2012 the Company capitalized $0.5 and $1.5 million (March 31, 2011 - $0.2 million and $0.2 million) of directly attributable expenses, $9.9 million and $29.8 million (March 31, 2011 -$9.2 million and $9.2 million) of

interest costs and $2.3 million and $6.6 million (March 31, 2011 - $2.1 million and $2.1 million) of debt service costs relating to property, plant and equipment.

STP-McKay Phase 1 assets amounting to $632.5 million at March 31, 2012 (June 30, 2011 $290.9 million) are currently not being depleted as the project is currently under construction and production has not commenced.

In determining the unit-of-production depletion charge on recoverable reserves, future development costs of $128.0 million (June 30, 2011 $141.7 million) were included in property, plant and equipment. No impairment losses were recognized during the current or the prior year quarter.

7. Long-term debt:

	Note	**March 31, 2012**	June 30, 2011
Revolving credit facility (CDN$30 million)	(a)	$-	$ -
Second lien term loan (US$271.6 million)		**271,318**	263,857
Financing transaction costs on second lien term loan		**(15,867)**	(15,867)
Amortization of financing costs		**3,258**	1,252
Less current portion of second lien term loan		**(2,748)**	(2,652)
	(b)	**255,961**	246,590
Convertible debentures (CDN$172.5 million)		**172,500**	172,500
Financing transaction costs on convertible debentures		**(6,339)**	(6,339)
Amortization of financing costs and equity		**7,172**	2,622
Equity component of convertible debentures		**(36,225)**	(36,225)
	(c)	**137,108**	132,558
Long-term debt		**$393,069**	$379,148

(a) Revolving credit facility (due January 7, 2014):

The Company has a $30 million revolving credit facility ("facility") with a syndicate of banks. The facility bears interest at a floating rate based on Canadian dollar prime rate, US dollar base rate, bankers' acceptances or LIBOR plus a credit spread above the reference rate. Undrawn amounts are subject to standby fees at approximately 1.4% of the undrawn amount. The facility matures on January 7, 2014 and is extendable at the lenders' discretion. The facility is collateralized by a first ranking security interest on all present and future assets of the Company.

As at March 31, 2012, $1.5 million of letters of credit were issued and outstanding pursuant to the facility. As such, the Company has $28.5 million available under the facility. For the three and nine months ending March 31, 2012 respectively $0.2 million (2011 - $0.1 million) and $0.4 million (2011 - $0.2 million) was incurred in interest and finance fees.

The facility contains various non-financial covenants that, among other things, restrict the Company with respect to issuing additional debt, making investments and loans, paying dividends, altering the nature of the business and undertaking corporate transactions. The facility has certain financial covenants that include:

- a minimum EBITDA (defined as earnings before finance charges, taxes, depletion, depreciation, accretion, risk management contract gains or losses, stock based compensation expenses and foreign exchange gains and losses) covenant during the construction period of the STP-McKay Phase 1 project of not less than US$35 million based on the 12 months trailing EBITDA;
- a PV-10 (pre-income tax present value of future cash flows from proved and probable reserves utilizing a 10% discount rate) to secured debt ratio starting at 1.75:1 and increasing to 3.00:1 during the term of the facility;
- a secured leverage ratio (the ratio of the term loan and facility debt to the last 12 months trailing EBITDA) after completion of STP-McKay Phase 1 project shall not be greater than 5.0:1 and reduces to 2.75:1 during the term of the facility; and
- debt drawn under this facility to the last 12 months trailing EBITDA ratio shall not exceed 2.0:1.

The Company is in compliance with all covenants under the facility as of March 31, 2012.

(b) Second lien term loan (due January 7, 2016):

The Company raised US$275 million under a second lien term loan ("term loan") for the funding of the STP-McKay project. The term loan bears interest on a floating basis at either the LIBOR rate plus a margin of 8.5% with a LIBOR floor of 2% or the U.S. base rate plus a margin of 7.5% with a U.S. base rate floor of 3%, depending upon whether a Euro loan or a US prime loan is drawn. The term loan requires scheduled quarterly payments of accrued interest and principal in an amount of 0.25% of the outstanding amount with the remaining balance of the term loan due on January 7, 2016. Transaction costs in relation to the issuance of the term loan were $15.9 million. The term loan is secured by a second ranking security interest on all present and future assets of the Company and is guaranteed by all of its subsidiaries. The effective annualized interest rate for the three and nine months ended March 31, 2012 was 12.3% which includes interest and amortization of the applicable financing costs.

The term loan contains various non-financial covenants that, among other things, restrict the Company with respect to issuing additional debt, making investments and loans, paying dividends, altering the nature of the business and undertaking corporate transactions. The term loan is subject to the same covenants as the facility discussed in note 7(a) except that it

does not include a debt to EBITDA ratio covenant. The Company is in compliance with all covenants under the term loan as of March 31, 2012.

At any time prior to January 7, 2016, the Company may prepay all or part of the term loan. The prepayment option is 102% prior to January 7, 2013, is 101% from January 7, 2013 to January 7, 2014 and par after January 7, 2014 of principal outstanding. Upon change of control of the Company, the term loan requires the Company to make an offer to repay at 101% of the principal outstanding. No value was ascribed to the prepayment option as the fair value of this option was not significant at the date of issue or at March 31, 2012.

As at March 31, 2012, US$50 million of the funds from the term loan is held in a separate collateral escrow account with the lender. These funds are available for use providing the Company is not in default of its covenants. After the completion of STP-McKay project, the Company is permitted to use any funds remaining in the deposit account to prepay amounts owing under the term loan at par.

The term loan is translated into Canadian dollars at the period end exchange rate of $1 US = $0.9991 CDN (June 30, 2011 - $0.9643).

(c) Convertible debentures (due June 30, 2016):

The Company issued subordinated unsecured convertible debentures with a face value of $172.5 million on January 7, 2011 for the STP-McKay project. Interest is payable on a fixed basis semi-annually on June 30 and December 31 of each year at the rate of 6%. The convertible debentures mature on June 30, 2016, unless converted prior to that date. The convertible debentures are convertible at any time into common shares, at the option of the holder, at a conversion price of $2.15 per share.

The convertible debentures are redeemable on or after June 30, 2014 by the Company for shares, in whole or in part, at a price equal to the principal amount of the convertible debentures to be redeemed, plus accrued and unpaid interest, provided that the market price of the Company's common shares is at least 130% of the conversion price of the convertible debentures for 20 consecutive trading days.

Transaction costs related to the debt component of the convertible debentures were $6.3 million. These costs are amortized over the expected life of the convertible debentures using the effective interest method.

As at the date of issuance, the value of the conversion feature of the convertible debentures was accounted for as a separate component of equity in the amount of $25.3 million (after adjusting for related transaction costs of $1.7 million and future income tax adjustments of $9.3 million). The debt component was measured at the issue date as the present value of cash payments of interest and principal under the terms of the convertible debentures using a

discount rate of 12.5%. The effective annualized interest rate of the convertible debentures, after giving consideration to the conversion feature option and transaction costs, is 12.2%.

(d) Required debt principal payments:

The required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

	Term loan	Convertible debentures	**Total**
2012	$687	$-	**$687**
2013	2,748	-	**2,748**
2014	2,748	-	**2,748**
2015	2,748	-	**2,748**
2016	262,389	172,500	**434,889**
Total	$271,320	$172,500	**$443,820**

8. Decommissioning liability:

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the liability associated with the retirement of petroleum and natural gas properties and equipment including well sites, gathering systems and processing facilities.

	Nine months ended March 31, 2012	Year ended June 30, 2011
Balance, beginning of period	**$22,127**	$10,185
Liabilities assumed on acquisition	**-**	1,045
Additions	**8,972**	10,199
Dispositions	**(1,159)**	-
Effect of change in estimates	**7,632**	878
Abandonment costs	**-**	(283)
Accretion	**56**	103
Balance, end of period	**$37,628**	$22,127

The total undiscounted amount of estimated cash flows required to settle the liability is $83.3 million (June 30, 2011 - $56.1 million), which has been discounted using a risk free rate of 2.3% and an inflation rate of 2.5%. Settlements will be funded from general corporate resources at the time of the properties' retirement and removal during the next 2 to 41 years.

9. Share capital:

(a) Authorized:

Unlimited common shares without par value
Unlimited first preferred shares without par value

(b) Issued:

	Number of shares	Amount
Balance, July 1, 2010	322,695	$283,603
Exercise of options	2,421	2,743
Cancelled (1)	(42)	-
Acquisition of North Peace	14,093	20,153
Balance, June 30, 2011	339,167	306,499
Exercise of options	1,980	2,580
Exercise of warrants	158	160
Balance, March 31, 2012	**341,305**	**$309,239**

(1) The share cancellations were the result of an acquisition whereby the amalgamation agreement provided for the cancellation of shares that were not exchanged into Company shares by a specified date.

(c) Stock options:

The Company has implemented a stock option plan for directors, officers and employees.

	Number of options	Weighted average exercise price
Balance, July 1, 2010	19,395	$1.05
Granted	7,574	1.51
Exercised	(2,421)	0.53
Forfeited	(549)	1.84
Balance, June 30, 2011	23,999	1.23
Granted	1,865	1.53
Exercised	(1,980)	0.67
Forfeited	(289)	1.46
Expired	(50)	0.50
Balance, March 31, 2012	**23,545**	**$1.30**

The following table summarizes information about the stock options outstanding at March 31, 2012:

	Outstanding			Exercisable		
Range of exercise price	Options	Weighted average exercise price	Weighted average remaining life (years)	Options	Weighted average exercise price	Weighted average remaining life (years)
$0.10 - $0.15	1,320	$0.10	1.71	1,320	$0.10	1.71
$0.50 - $0.75	4,531	0.56	2.59	4,532	0.56	2.59
$0.77 - $1.15	3,126	0.98	2.23	2,702	0.97	2.04
$1.17 - $1.75	9,953	1.44	3.99	1,180	1.35	3.46
$1.76 - $1.92	3,215	1.89	1.62	2,507	1.90	0.84
$3.15 - $3.15	1,400	3.15	0.24	1,400	3.15	0.24
	23,545	**$1.30**	**2.81**	**13,641**	**$1.18**	**1.91**

The weighted average fair value of the options granted is estimated at $0.80 (2011 – $0.70) on the dates of grant using a Black-Scholes option pricing model with the following assumptions:

March 31,	**2012**	2011
Risk free interest rate	**1.5%**	2.4%
Expected life in years	**4.88**	4.04
Expected volatility	**100.0%**	124.6%
Forfeiture rate	**1.15%**	0.58%
Dividend yield	**0%**	0%

(d) Warrants:

Warrant transactions are summarized as follows:

	Number of warrants	Weighted average exercise price
Balance, June 30, 2010	2,127	$1.93
Warrants assumed on acquisition	1,953	4.05
Expired	(3,891)	3.04
Balance, June 30, 2011	189	$1.01
Exercised	(158)	1.01
Expired	(31)	1.01
Balance, March 31, 2012	**-**	**-**

(e) Per share amounts:

The Company excluded 5.8 million options (2011 – 5.0 million) and nil warrants (2011 – nil) and all convertible debentures (2011 – all) for the nine months ended March 31, 2012 and 7.3 million options (2011 – 4.1 million) and nil warrants (2011 – 0.2 million) and all convertible debentures (2011 – all) for the three months ended March 31, 2012, from the calculation of the diluted weighted average number of shares as they were anti-dilutive.

10. Contributed surplus:

	Nine months ended March 31, 2012	Year ended June 30, 2011
Balance, beginning of period	**$24,393**	$23,064
Options exercised	**(1,248)**	(1,481)
Stock-based compensation	**4,080**	2,810
Balance, end of period	**$27,225**	$24,393

11. Capital management:

The Company's objective for managing its capital structure is to ensure it has the financial capacity, liquidity and flexibility to fund investment in its in-situ oilsands resources and development of its existing producing properties.

The Company considers its capital structure to include shareholders' equity and long term debt which totals $762.9 million at March 31, 2012 (June 30, 2011 - $732.3 million). The Company's in-situ oilsands properties require significant capital investment prior to cash flow generation. In order to maintain the capital structure, the Company may from time to time issue shares and adjust its capital spending to manage current and projected debt levels and in light of changes in economic conditions. The Company monitors its bank debt level and working capital in order to assess capital and operating efficiency.

The Company's share capital and cash flow is not subject to external restrictions except for certain financial restrictive covenants under long-term debt (note 7). The Company has not paid or declared dividends since its reorganization of management and change in principal business on March 2, 2006.

12. Financial instruments:

The Company is exposed to the following risks in respect of certain financial instruments held:

(a) Credit risk

Credit risk arises from the potential that a counterparty will fail to perform its obligations and cause a financial loss to the Company. The Company is exposed to credit risk from the Company's accounts receivable from purchasers of the Company's natural gas, crude oil and natural gas liquids and from its joint venture partners. Accounts receivable from purchases of the Company's natural gas, crude oil and natural gas liquids are normally collected the 25th day of the month following the production. The Company's policy to mitigate credit risk is to establish marketing relationships with large and reputable companies. The Company has not experienced any material credit loss in the collection of accounts receivable. The Company, however, does receive the majority of its revenue from a single entity and as such is exposed to the credit risks of this company.

Joint venture accounts receivable are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate risk from joint venture accounts receivable by obtaining partner approval of significant capital expenditures prior to the commencement of the project. The Company does not typically obtain collateral from joint venture partners, however, in the event of non-payment the Company has the ability to withhold future production from joint venture partners where the Company is the operator.

The Company is potentially exposed to credit risk with respect to cash amounts held in individual banking institutions for balances that are in excess of nominal guaranteed amounts. Cash and cash equivalent balances at March 31, 2012 were held with two banking institutions in Canada; $32.9 million with one and $50.0 million with the other. The Company periodically monitors published and available credit information for all of its banking institutions.

(b) Market risk

The Company recognizes the fair value of its risk management contracts on the balance sheet each reporting period. The change in fair value is recognized as a gain or loss on the statement of operations. The fair value is at a Level 2 which is based on valuation models and techniques where the significant inputs are derived from quoted market prices or indices. At March 31, 2012 the fair value is estimated to be an unrealized gain of $2.8 million (June 30, 2011 - $0.6 million gain). The following table summarizes the change in fair value of the Company's risk management contracts:

	March 31, 2012	June 30, 2011
Balance, beginning of period	**$570**	**$** 273
Unrealized gain during the period	**2,183**	297
Balance, end of period	**$2,753**	$570

The Company has the following outstanding contracts as of March 31, 2012:

Type	Contract Term	Volume	Price
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	900 bbl/day	US$85.00- $115.75
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	500 bbl/day	US$90.00- $110.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	700 bbl/day	US$90.00- $115.05
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.10
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.12
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	700 bbl/day	US$90.00- $100.00
Oil collar (WTI)	Jan 1, 2013 to Dec 31, 2013	1,000 bbl/day	US$90.00- $114.50
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.00 CAD/USD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.0290 CAD/USD
Differential swap (WTI)	Jan 1, 2012 to Dec 31, 2012	1,000 bbl/day	WTI-US $17.25
Differential swap (WTI)	Jan 1, 2012 to Dec 31, 2012	500 bbl/day	WTI-US $16.95

The following table summarizes the consolidated statement of operations effects of the Company's risk management contracts:

	Three months ended March 31		Nine months ended March 31	
	2012	2011	**2012**	2011
Unrealized gain (loss)	**$4,477**	$(4,671)	**$2,183**	$(5,673)
Realized gain	**738**	138	**1,132**	162
	$5,215	$(4,533)	**$3,315**	$(5,511)

(c) Liquidity risk

Liquidity risk is that risk that the Company will not have sufficient funds to repay its debts and fulfill its obligations. To manage this risk, the Company follows a conservative financing philosophy, prefunds major development projects, monitors budgets to control costs, and monitors its operating cash flow and working capital.

(d) Fair value

The carrying value of accounts receivable and accounts payable and accrued liabilities approximate the fair value of the respective assets and liabilities due to the short term nature of those instruments. The risk management contracts are recognized on the balance sheet at a Level 2 fair value which is discussed above in note 12(b). Long-term debt is carried at amortized cost and the fair value, based on current market prices, is estimated to be $459.6 million, consisting of the term loan of $276.7 million and the convertible debentures of $182.9 million, including the equity component, based on current market prices.

(e) Interest rate risk

The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest (Note 7).

(f) Currency risk:

The Company is exposed to fluctuations in foreign currency primarily as a result of its U.S. dollar denominated second lien term loan facility, U.S. cash, crude oil sales based on U.S. dollar indices and commodity price contracts that are settled in U.S. dollars. The Company's working capital as of March 31, 2012 denominated in U.S. dollars is $78.6 million (June 30, 2011 - $214.4 million).

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The following table summarizes the components of the Company's net foreign exchange loss:

	Three months ended March 31		Nine months ended March 31	
	2012	2011	**2012**	2011
Unrealized foreign exchange (gain) loss on translation of:				
U.S. denominated second term loan facility	**$(4,873)**	$(6,035)	**$9,559**	$(6,035)
Foreign currency denominated cash balances	**2,461**	5,362	**(8,537)**	5,362
Unrealized foreign exchange (gain) loss	**(2,412)**	$(673)	**$1,022**	$(673)

13. Commitments:

At March 31, 2012 the Company is committed to annual lease payments, under the terms of leases for its head office space and other equipment:

	Amount
2012	**$138**
2013	**496**
2014	**496**
2015	**360**
2016	**87**
Thereafter	**65**
Total	**$1,642**

At March 31, 2012, as part of normal operations relating to the construction of the STP-McKay Phase 1 SAGD project, the Company has entered into a total of $28.1 million in capital expenditure commitments to be made over the next year.

At March 31, 2012, as part of normal operations, the Company has entered into the following fixed price gas purchase contracts:

Type	Contract Term	Volume	Price
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.14
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.00
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$3.93
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	500 gj/day	$3.86
Natural gas fixed purchase (AECO)	Jul 1, 2012 to Dec 31, 2012	2,000 gj/day	$2.96
Natural gas fixed purchase (AECO)	Jul 1, 2012 to Dec 31, 2012	1,000 gj/day	$2.75

14. Petroleum revenue:

	Three months ended March 31		Nine months ended March 31	
	2012	2011	**2012**	2011
Petroleum sales	**$24,399**	$18,791	**$67,156**	$63,006
Other income	**1,539**	148	**1,545**	148
Royalties	**(3,925)**	(2,959)	**(10,054)**	(10,105)
Saskatchewan resource surcharges	**(415)**	(315)	**(1,148)**	(1,062)
Petroleum revenue	**$21,598**	$15,665	**$57,499**	$51,987

15. Finance expense:

	Three months ended March 31		Nine months ended March 31	
	2012	2011	**2012**	2011
Standby fees on revolving credit facility	**$168**	$34	**$438**	$183
Accretion of decommissioning liability	**1**	24	**56**	49
Total finance expense	**$169**	$58	**$494**	$232

16. Transition to IFRS:

As stated in Note 2, these are the Company's March 31, 2012 condensed interim consolidated financial statements for part of the period covered by the first annual consolidated financial statements to be prepared in accordance with IFRS. These accounting policies remain the same as those applied in the September 30, 2011 condensed interim consolidated financial statements. In addition, note 16 to the September 30, 2011 condensed interim consolidated financial statements provides disclosure on the exemptions the Company has chosen for the transition to IFRS, the statement of financial position at the date of transition, and other required Canadian GAAP/IFRS reconciliations.

Reconciliation of consolidated statement of financial position and shareholders' equity at the end of the comparative interim period, March 31, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$414,531	$-	$414,531
Trade receivables		11,552	-	11,552
Prepaid expenses and deposits		1,547	-	1,547
		427,630	-	427,630
Non-current assets:				
Exploration and evaluation assets	a	-	153,235	153,235
Property, plant and equipment	a,b,c	430,289	(149,703)	280,586
		$857,919	$3,532	$861,451
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$75,002	$-	$75,002
Risk management contracts		5,400		5,400
Current portion of long-term debt		2,672		2,672
		83,074	-	83,074
Non-current liabilities:				
Long-term debt	f	374,803	4,524	379,327
Decommissioning liability	c	7,851	3,887	11,738
Deferred income tax liability	d	34,046	8,883	42,929
		499,774	17,294	517,068
Shareholders' equity:				
Share capital	d	303,258	2,024	305,282
Equity component of convertible debentures	f	39,821	(14,537)	25,284
Contributed surplus	e	24,725	(447)	24,278
Deficit	c,d,e	(9,659)	(802)	(10,461)
		358,145	(13,762)	344,383
		$857,919	$3,532	$861,451

Reconciliation of consolidated statement of comprehensive income for the three months ended March 31, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenues and Other Income				
Petroleum revenue, net of royalties	d	$15,665	$-	$15,665
Gain on risk management contracts		(4,533)	-	(4,533)
		11,132	-	11,132
Expenses:				
Operating		3,821	-	3,821
Exploration and evaluation	a	-	10	10
General and administrative		2,626	-	2,626
Finance	c	34	24	58
Foreign exchange (gain) loss		(673)	-	(673)
Depletion and depreciation	b,c	7,603	(1,286)	6,317
Share-based compensation	e	553	(81)	472
		13,964	(1,333)	12,631
Other				
Gain on acquisition		-	-	-
		-	-	-
Loss before income taxes		(2,832)	1,333	(1,499)
Deferred income tax expense	d	(1,415)	(195)	(1,610)
(Loss) income and comprehensive (loss) income		($1,417)	$1,528	$111

Reconciliation of consolidated statement of comprehensive income for the nine months ended March 31, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenues and Other Income				
Petroleum revenue, net of royalties	d	$51,987	$-	$51,987
Gain on risk management contracts		(5,511)	-	(5,511)
		46,476	-	46,476
Expenses:				
Operating		11,696	-	11,696
Exploration and evaluation	a	-	353	353
General and administrative		6,340	-	6,340
Finance expense	c	183	49	232
Foreign exchange (gain) loss		(673)	-	(673)
Depletion and depreciation	b,c	26,719	(4,470)	22,249
Share based compensation	e	2,343	(289)	2,054
		46,608	(4,357)	42,251
Other:				
Gain on acquisition		3,585	-	3,585
		3,585	-	3,585
Income before income taxes		3,453	4,357	7,810
Deferred income tax (recovery) expense	d	(168)	565	397
Net income and comprehensive income		$3,621	$3,792	$7,413

Notes:

(a) Exploration & Evaluation assets

Under the previous GAAP exploration and evaluation assets were included in the full cost pool of property, plant and equipment. Under IFRS these assets must be classified separately. At transition the company reclassified $172.5 million from property, plant & equipment to exploration & evaluation assets. Similarly the company reclassified $153.2 million at March 31, 2011.

Exploration and evaluation expense for the three and nine months ended March 31, 2011 relates to expired land and was $0.1 million and $0.4 million respectively.

(b) Depletion and Depreciation expense

Under the previous GAAP, depletion and depreciation was calculated on a unit-of-production basis for oil and gas properties using proved reserves on a cost center basis that was defined as a country. Under IFRS depletion is calculated using recoverable reserves on a component basis which has resulted in a decrease in depletion expense and an increase in the carrying value of property, plant, and equipment. For the three and nine months ended March 31, 2011 this amount was $1.3 million and $4.5 million respectively.

(c) Decommissioning liability

Under the previous GAAP, asset retirement obligations were discounted using a credit-adjusted risk-free rate of 8.0%. Under IFRS a risk-free rate of 3.1% has been used at transition date July 1, 2010 which resulted in an increase to the decommissioning liability of $3.7 million with the offsetting charge recognized in retained deficit. At March 31, 2011, a rate of 3.55% was used with an increase to the decommissioning liability of $3.9 million.

In addition, under the previous GAAP, accretion of the discount was included in depletion and depreciation while under IFRS it is included in net finance expense. For the three and six months ending March 31, 2011, $0.1 million was reclassified from DD&A to finance expense and offset by a reduction in accretion expense of $0.1 million.

(d) Deferred income tax

Flow-through shares – Under Canadian income tax legislation a company can issue flow-through shares whereby the company incurs qualifying expenditures relating to oil and gas exploratory and development activities and renounces the related income tax deductions to the investors. Generally the flow-through shares are offered at higher than prevailing quoted prices of the shares due to the benefit of the tax deduction to investors. Under IFRS this ‘premium’ of the issued share price over the market price is an adjustment to share capital with the offset to retained earnings. At transition date this amount was $2.0 million including the deferred tax effect.

Share issue costs – Subsequent to initial recognition, these were treated as a temporary difference under the previous GAAP but under IFRS these are treated as an adjustment to share capital when the tax rate changes. At transition date this adjustment was $0.1 million.

Convertible debentures – The convertible debentures liability and equity portions were adjusted for the value of a redemption option. The deferred tax impact on the equity component was a permanent tax difference under previous GAAP, however, under IFRS this is a temporary

difference. This adjustment has reduced the equity portion of the convertible debenture and increased deferred tax by $9.3 million for the year ended June 30, 2011. This change also reduced the deferred income tax expense as at June 30, 2011 by $0.7 million for the period ended June 30, 2011. The expense was reduced because the temporary difference of $9.3 million is reversed over time, as the debt portion of the convertible debenture is accreted.

Deferred income tax calculated according to IFRS is substantially similar to previous GAAP and arises from the differences in the accounting and tax bases of assets and liabilities. Where balances have changed due to IFRS differences, the amount of deferred income tax liability will be impacted.

Under the previous GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

Under the previous GAAP, Saskatchewan resource payments were classified as a tax however under IFRS they are now classified as a royalty and netted to petroleum revenue.

(e) Share-based compensation

Under the previous GAAP, the company recognized an expense related to share-based payments on a straight-line basis and did not include an estimate of forfeitures. Under IFRS the company is required to recognize the expense over the individual vesting periods for the graded vesting awards and to estimate a forfeiture rate. At transition date this resulted in a $0.2 million decrease to contributed surplus and an increase to retained earnings. At March 31, 2011 this amount was $0.4 million.

(f) Long term debt and equity component of convertible debentures

Under IFRS and previous GAAP, the convertible debentures are treated as a compound financial instrument. However, under IFRS, the value of the embedded call option is considered a part of the liability component and as a result, the equity portion of the convertible debenture was reduced by $4.5 million with a corresponding increase to long-term debt. In addition, under IFRS, the equity component was adjusted for deferred taxes, see note (d), resulting in a decrease of the equity component of convertible debentures of $14.5 million. The effective interest rate calculation was also adjusted to reflect the IFRS changes above.

(g) Adjustments to the consolidated statement of cash flows

The transition from the previous GAAP to IFRS had no significant impact on cash flows generated by the Company.