SOUTHERN PACIFIC RESOURCE CORP.

ANNUAL REPORT

Full Steam Ahead

CONTENTS

With production ramping up at McKay, Southern Pacific is driving forward.

The past year was filled with achievements for Southern Pacific and we're proud to be the only company to bring a new SAGD project on stream in 2012. First steam began circulating in July of this year.

With our rail agreement in place, we are also the first company that is able to transport our bitumen from the plant gate directly to the refinery with dedicated on loading and off loading facilities at each end of the track. This should provide a significant increase in netbacks.

McKay Facility
June 2011

1.2 million

man-hours invested to complete Phase 1
of the McKay facility

200%

increase in new talent hired
in the past year

4,50

of secured
direct acce


0 km
transportation with
ss to market
12,000 bbl/d
production capacity from
Phase 1 enroute to a total
design capacity of 36,000 bbl/d

Highlights for the Fiscal Year Ended June 30, 2012

Completed construction of the STP-McKay Phase 1 Thermal Project ("STP-McKay Phase 1") on time and within 4% of the original budget, at a cost of $468 million. First steam began circulating to the first well pad on July 1, 2012 followed by the second well pad on July 13, 2012. Oil production is anticipated within three to four months after those dates.

Identified an opportunity to increase STP-McKay Phase 1 from 12,000 bbl/d of bitumen to 18,000 bbl/d. The Phase 1 expansion is expected to add incremental oil volumes at a significantly lower cost and a faster timeline than a new plant.

Pursued plans for STP-McKay Phase 2, the additional 18,000 barrels per day (bbl/d) phase would begin steaming in the second quarter of 2017. Production would ramp up and be expected to reach design capacity of 36,000 bbl/d within 18 months of first steam.

Achieved funds from operations of $46.9 million for fiscal 2012.

Increased proven and probable reserves ("2P") by 38% to 249 million barrels ("MMbbl") from 181 million barrels, due primarily to the expansion plans for STP McKay. The expanded capacity from Phase 1 Expansion and Phase 2 allowed both an acceleration of the previously booked reserves and the reassignment to the probable category of 53 MMbbl of best estimate contingent resources.

Finalized an arrangement to transport and market STP-McKay Phase 1 bitumen by rail. This agreement is designed to significantly increase the Company's plant gate netback and secure access to the world's largest consuming market for heavy oils.

Averaged overall production from STP-Senlac of 3,639 bbl/d for the year.

Subsequent to the end of fiscal 2012, Southern Pacific completed a successful equity financing of $80.65 million through a bought-deal financing. The Company plans to use the proceeds to fund its continued growth and increase working capital flexibility.

Forward Focused

Message to Shareholders

Southern Pacific's growth plan is moving full steam ahead. While fiscal 2012 was focused on building our STP-McKay Thermal Project from the ground up, fiscal 2013 will be about delivering.

We're pleased to report that we're right on track. We completed construction of STP-McKay Phase 1 at the end of fiscal 2012 and began circulating steam to the first well pad on July 1, 2012. First steam was a key milestone for Southern Pacific because it represented the start-up of our first major project. In fact, we will be the only company to bring a new steam-assisted gravity drainage ("SAGD") project on stream in 2012. We plan to circulate steam through the SAGD wellbores for three to four months, after which bitumen production is expected to follow. Production from Phase 1 will ramp up slowly but steadily and is expected to peak at about 12,000 bbl/d within 18 months.

As a management team, we have worked hard over the last few years to earn a reputation for doing what we said we would do. Since we purchased our first oil sands lease in July 2007 for $2.3 million and then acquired the STP-Senlac Thermal Project in Saskatchewan in November 2009 for $87 million, we've been hitting targets, controlling costs and setting the stage for significant growth on our remaining undeveloped oil sands leases in Alberta.

Our first major project is progressing according to plan. We discovered STP-McKay through corehole drilling during the winter of 2007/08. After another season of delineation drilling over the winter of 2008/09, we submitted an application to Alberta's regulatory authorities for a 12,000 bbl/d facility. The application was approved in October 2010 and project construction began in December 2010. After 18 months of building, Phase 1 commenced operations on the first day of fiscal 2013. The total project construction cost was $468 million, which is within 4% of the original budget. This is a noteworthy achievement.

Southern Pacific has already filed the application for two expansions at STP-McKay. We announced the first phase of our expansion plans on May 10, 2012, adding 6,000 bbl/d to Phase 1 for a total of 18,000 bbl/d. The application for the Phase 1 expansion was incorporated into the approval process for STP-McKay Phase 2, which we announced in November 2011. Phase 2 would add another 18,000 bbl/d, resulting in total bitumen processing design capacity of 36,000 bbl/d. The Phase 2 application is well advanced and approval is expected in late calendar 2013.

In fiscal 2013, we plan to deliver results in more ways than one. On July 27, 2012, we announced an innovative agreement to transport our bitumen from STP-McKay by rail to the U.S. Gulf Coast. We are the first oil sands company to adopt a complete rail marketing solution to get its bitumen from the plant gate to the refinery. Our five-year marketing agreement with multiple parties includes transporting bitumen 60 km by truck to a terminal in Lynton, Alberta, 4,500 km by train to Natchez, Mississippi and then by barges to refineries on the Gulf Coast. This agreement is significant because it ensures access to a key market at advantageous prices during a time when pipeline capacity out of Canada is expected to be tight. Historical pricing fundamentals suggest that transporting bitumen by rail to the U.S. Gulf Coast will provide stronger netbacks than current pipeline options to the U.S. Midwest. The Gulf Coast offers better pricing for diluted bitumen by offering access to Brent based pricing versus West Texas Intermediate based pricing and lower costs because rail requires less diluent blending than pipelines.

We are also testing the benefit of a rail marketing solution at our STP-Senlac Thermal Project in Saskatchewan. Test volumes are currently being hauled to a newly completed rail terminal located at nearby Unity, Saskatchewan. If the option develops as planned, it should provide Southern Pacific with a locked in premium to the Western Canadian Select oil benchmark pricing. We will monitor the success of this program and allocate more volumes to this new market if it makes sense. Our operations at STP-Senlac have been running smoothly. We've received approval to drill another three SAGD well pairs at Phase K, which is expected to fill the plant to capacity for another year or longer. The first well of Phase K is scheduled to spud in mid-October, with first oil anticipated for February 2013.

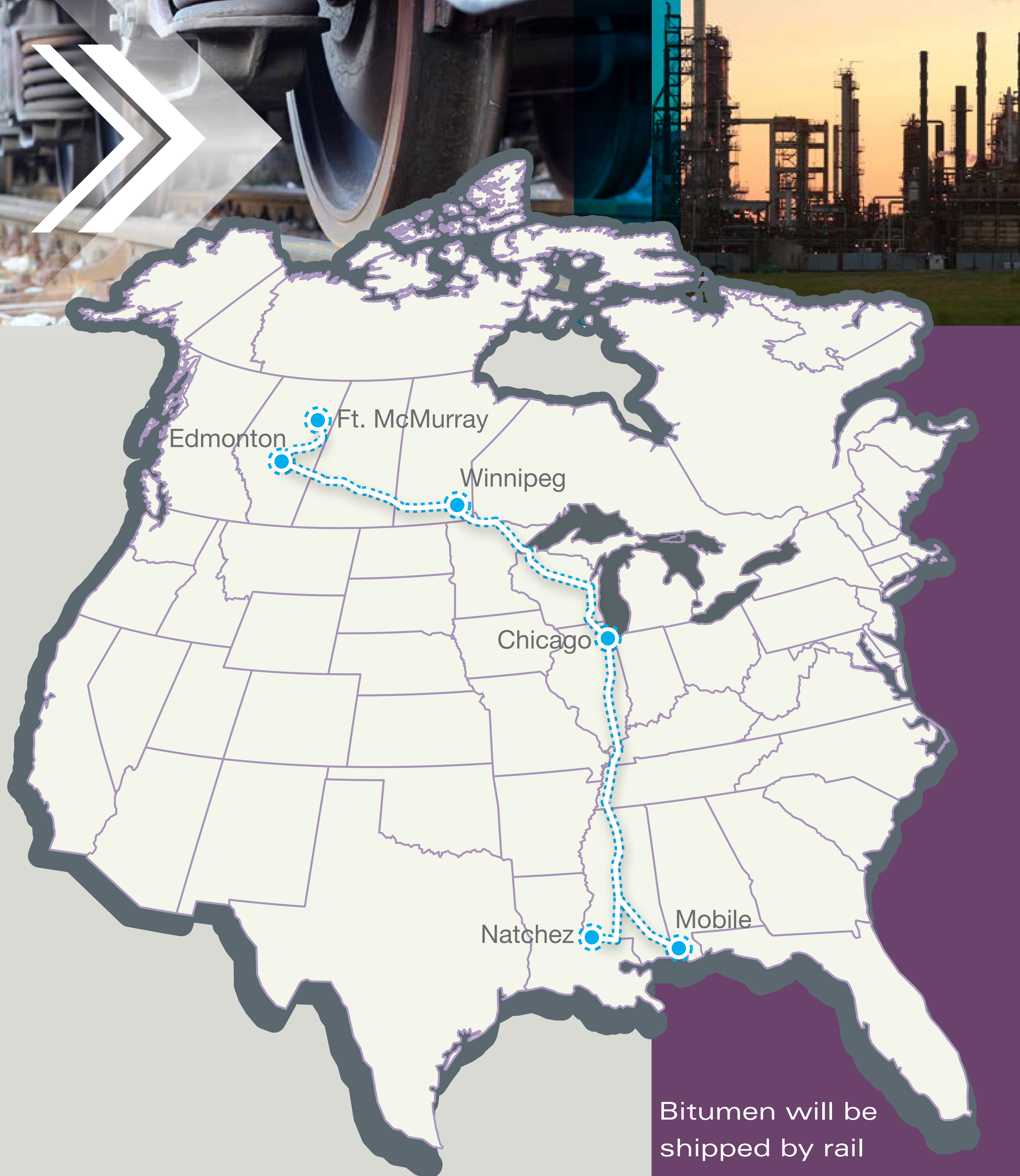
Southern Pacific has come a long way, but we are not done yet. It won't be long before we will have material production and cash flow from STP-McKay Phase 1, Phase 1 expansion and Phase 2. While our focus is on ramping up production at STP-McKay, we also have five exploration blocks in Alberta's oil sands that represent significant upside for future in-situ oil sands projects. We are looking forward to sustained cash flow from our two producing projects which will allow us to return our focus to these growth blocks, which had been parked while we finished up Phase 1 of STP-McKay.

I would like to thank our talented team who continue to outperform as we tap into massive bitumen and heavy oil reserves in Western Canada. We've attracted strong people over the past year, increasing from 50 to 117 full-time employees. Our technical people in both Senlac and McKay deserve special recognition for getting the job done right, on time, and safely. I would also like to thank our Board of Directors for their tireless efforts. Finally, I would like to thank both our long-time shareholders and new shareholders. Thank you for joining us on this journey as we move full steam ahead in fiscal 2013.

On behalf of the management team,

Byron Lutes, President & CEO
Southern Pacific Resource Corp.

October 2012



Bitumen will be shipped by rail

4,500 km

Direct Transport to the Gulf Coast

Southern Pacific finalized an innovative five-year agreement on June 27, 2012 to transport its bitumen to the U.S. Gulf Coast via rail.

The Company expects rail transportation to secure access to the world's largest market for heavy crude oil. It should also significantly increase its plant gate bitumen netback by reducing its diluent costs and by realizing higher Brent-based pricing.

Southern Pacific's bitumen volumes will be trucked approximately 60 km from the STP-McKay plant gate to Lynton, Alta., a CN rail terminal located immediately south of Fort McMurray. From Lynton, volumes will be transferred into rail cars and shipped approximately 4,500 km over CN's network and a short-line rail partner to a terminal in Natchez, Miss. The bitumen will then be transferred to barges that will deliver the product as feedstock to refineries on the Gulf Coast.

There are a number of significant benefits to this rail-based solution. Lower diluent costs and secure access to the world's largest market for heavy crude are the key drivers. The Gulf Coast market for heavy crude currently trades at a premium to West Texas Intermediate. Alberta-based blended bitumen and diluent products arriving by pipeline into the Chicago, region of the U.S. suffer significant pricing discounts due to capacity constraints.

This rail agreement demonstrates that alternatives to conventional pipelines are available to market bitumen from the Athabasca oil sands. This has implications not only for Southern Pacific shareholders through higher netbacks, but also for Albertans through increased royalties and a safe and viable alternative for transporting bitumen.

Leading The Way

Management Team

From left to right:

Michael O'Krancy, P.Eng.
Vice President, Projects

Byron Lutes, P.Eng.
President & CEO

Glenn Miller
Vice President,
Land & Regulatory Affairs

Sheila Sterna, CMA
Manager, Accounting

Troy Bergfeldt, C.A.
Manager, Financial Reporting

Kirk Weich, B.Mgmt
Manager, Human Resources

Howard Bolinger, C.A.
Chief Financial Officer

Chad Harris, M.Sc.
Vice President, Exploration

Ron Clarke, P.Eng.
Chief Operating Officer

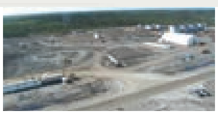
Chris Edwards, P.Eng.
Manager, Process Engineering

Wayne Beatty, P.Eng.
Vice President, Resource Development

Tim Bibby, B.Com., CET
Manager, Drilling & Completions

Jeff Barefoot, P.Eng., MBA
Vice President, Business Development

Kim Chiu, P.Eng.
Manager, Production &
Reservoir Engineering



Board of Directors

From left to right:

Dave Antony, C.A., Chairman
Ross D.S. Douglas, P.Eng., ICD.D., Director
Trevor Wong-Chor, L.LB., Secretary

Ward Mallabone, L.LB., Director
Tibor Fekete, P.Eng., Director
Jon P. Clark, M.S.Geol., Director

Ken Cullen, C.A., Director
Sid Dykstra, P.Eng., MBA, Director
Byron Lutes, P.Eng., President & CEO

Significant Increase in Year End Reserves

In a report prepared by GLJ Petroleum Consultants ("GLJ"), Southern Pacific's independent reserves evaluator, effective June 30, 2012 (the "GLJ Report"), Proved Developed and Producing ("PDP") reserves increased by more than 600% from the previous estimate dated June 30, 2011. The increase in PDP reserves is directly attributable to the STP-McKay Thermal Project becoming operational. There has also been a 38% increase in the Company's Proven plus Probable ("2P") reserves over the past fiscal year. This increase reflects revisions arising from the application submission for the Phase 1 Expansion and Phase 2 at the STP-McKay Thermal Project. Combined, a total nominal design capacity of 36,000 bbl/d of bitumen has been utilized to reflect the development plans for the 2P reserves category.

Despite having produced approximately 1.3 million barrels of heavy oil, the STP-Senlac Thermal Project's remaining Total Proved ("1P") and 2P remaining reserves increased by 0.9 and 0.5 million barrels of technical revisions in each category respectively. The increases reflect the strong performance of the project that have met or exceeded previous evaluations' performance predictions.

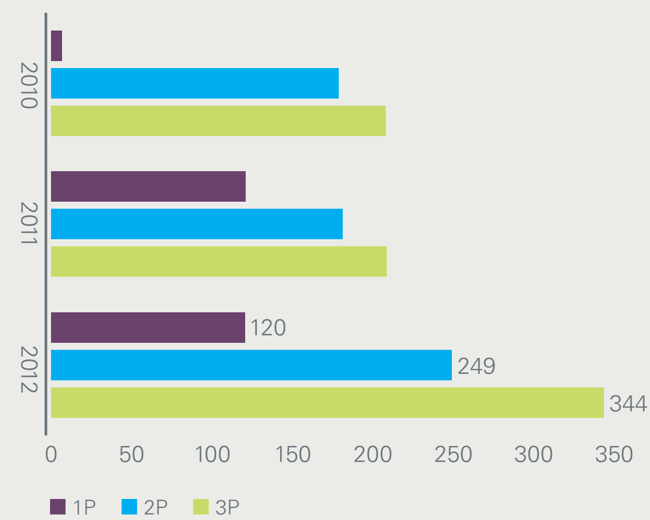
Below is a summary of the Company's reserves effective June 30, 2012. Southern Pacific has consistently grown its reserve asset base over the past three years and has also increased the certainty of the reserves, reflected in the large growth in its Total Proved ("1P") reserves.

Probable reserves means those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves.

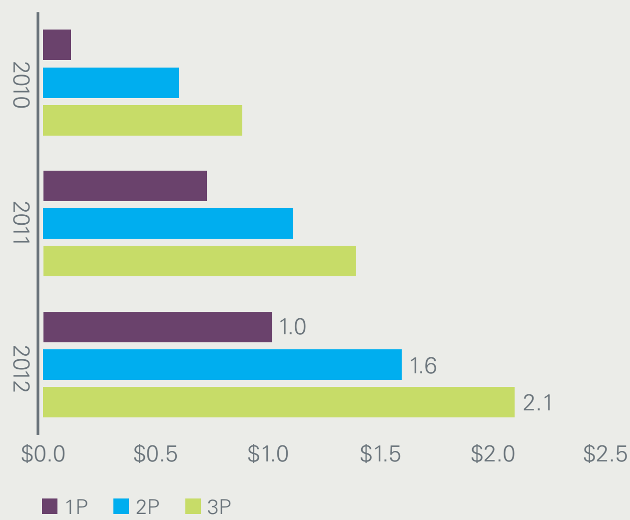
Possible reserves means those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible reserves.

Proved reserves means those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves.

Net Reserves (MMbbl)



Net Present Value ($billion)



(before tax, discounted at 10%)
Estimated values may not represent fair market value

Management's Discussion and Analysis for the Three and Twelve Months Ended June 30, 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 "2012" and "2011" are used throughout this document and refer to the fiscal years ended June 30, 2012 and 2011, respectively. References to "fourth quarter 2012" in this document refer to the three month financial period ended June 30, 2012. References to "fourth quarter 2011" in this document refer to the comparative three month financial period ended June 30, 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, 2012. This MD&A is dated September 24, 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 annual financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP").

Overall Performance

Highlights for the quarter and year ended June 30, 2012 include the following:

- Completed construction of Phase 1 of the STP-McKay Thermal Project ("STP-McKay Phase 1"). The total project construction was completed at a cost of $468 million, only 4% over the original budget. Steam began circulating to the first well pad on July 1, 2012 and the second well pad on July 13, 2012 with oil production expected in the fourth quarter of calendar 2012;
- Increased proven and probable reserves ("2P") by 38% to 249 million barrels from 181 million barrels primarily due to the filing of the application for the STP McKay Phase 1 Expansion and Phase 2;
- Reported a reclassification of 15.5 million barrels of proved, undeveloped reserves ("PUD") to proved developed producing ("PDP) reserves, increasing PDP reserves by 600% as a result of commencing steaming operations on the first 12 steam assisted gravity drainage ("SAGD") well pairs at STP-McKay;
- Finalized terms of a rail marketing arrangement for STP-McKay Phase 1 volumes which secures access to markets for the project's bitumen product and should also significantly increase its plant gate netback;
- Announced a 6,000 barrel per day ("bbl/day") expansion plan for its STP Phase 1 ("STP-McKay Phase 1 Expansion"), which would give the project a total nominal capacity of 18,000 bbl/day. This will allow the Company to accelerate its production growth forecast;
- Averaged overall production from STP-Senlac of 3,639 bbl/day for the year; and
- Achieved cash from operating activities before changes in non-cash working capital of $46.9 million for the year.

Outlook

Fiscal 2012 was Southern Pacific's busiest year in its history. The successful completion of the STP-McKay Thermal Project marks the end of a five year development plan that began with securing the lands, discovering the resource, preparing an application, completing the approval process and then constructing the project. However, this is only the beginning. Southern Pacific is now in the process of implementing its long term operations program at STP-McKay and is continuing to advance on its next planned projects.

In the near term, Southern Pacific is expecting major growth to its production profile. From first steam, which was achieved on July 1, 2012, the Company expects to ramp up the STP-McKay volumes through the next fiscal year, aiming towards the nominal plant capacity of 12,000 bbl/day. This production base, coupled with the STP-Senlac Thermal Project, should open up new opportunities for Southern Pacific.

On September 10, 2012, Southern Pacific entered into an agreement with a syndicate of underwriters to sell, on a bought deal basis 51.7 million common shares of the Company at a price of $1.45 per common share, for gross proceeds of approximately $75 million plus an over-allotment option of up 7.8 million common shares at the same price. Southern Pacific intends to use the proceeds from this offering to strengthen the Company's balance sheet while it ramps up the STP-McKay project. The offering is expected to close on or about September 28, 2012.

STP-Senlac

At the STP-Senlac Thermal Project, operations have been running consistently through all of calendar 2012 with the plant averaging a 99.2% on-time load factor over that period. Production averaged 3,639 bbl/day in fiscal 2012, with production currently averaging approximately 3,100 bbl/day. Phase J was brought on stream in January 2012, resulting in peak field rates of about 4,500 bbl/day in February. Since then, the field production has been declining normally as it does in between new phases.

In preparation for Phase K, the Company recently completed the drilling of a strat well. That well confirmed a better than prognosis 15 m thick oil zone in Phase K. The first well of Phase K should spud in mid-October, with production anticipated in February 2013. Regulatory approval for the drilling of Phase K was delayed by approximately three months due to recently introduced Saskatchewan regulations, which now require an environmental review of enhanced oil recovery scheme amendments. The new regulatory process has now been incorporated into the Company's development planning cycle and regulatory delays on future phases of development are not anticipated.

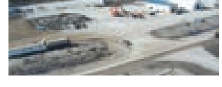
STP-McKay Phase 1 Operational Update

Operations continue to progress well at the STP-McKay Thermal Project as the steam circulation period advances on all of its first 12 SAGD well pairs. The first pad of six well pairs commenced steaming on July 1, 2012, with the second pad of six well pairs following on July 13, 2012. To date, the plant has been running consistently, delivering all steam requirements to the wellbores at a 99% on-time load factor. The wells are warming up in a manner that indicates good conformance along the horizontal sections. It is anticipated the wells will need three to four months of steam circulation before being placed into production. Southern Pacific expects production to begin in the fourth quarter of 2012. The project was completed at a total cost of $468 million.

The Company finalized its marketing arrangements on June 27, 2012. Under this arrangement, Southern Pacific expects to significantly increase its plant gate bitumen netback using rail transportation that reduces diluent costs, and offers access to Brent-based pricing as opposed to selling its bitumen into a pipeline that offers access to West Texas Intermediate (WTI) based pricing.

Southern Pacific's bitumen volumes will be trucked approximately 60 km from the STP-McKay plant gate to Lynton, Alta., a CN rail terminal located immediately south of Fort McMurray. From Lynton, volumes will be transferred into rail cars and shipped approximately 4,500 km over CN's network and a short-line rail partner to a terminal in Natchez, Miss. The bitumen will then be transferred to barges that will deliver the product as feedstock to refineries on the Gulf Coast.

There are a number of significant benefits to this rail-based solution for Southern Pacific. Diluent cost savings are a key driver for this arrangement. Diluent savings are achieved on two fronts. The amount of process diluent required at the



plant site will be significantly lower than what is required to meet pipeline specifications. By transporting bitumen via CN, Southern Pacific will only require process diluent to blend with its bitumen, thus lowering the total diluent requirements by approximately 33%. Secondly, Southern Pacific has the opportunity to backhaul lower priced diluent from the Gulf Coast utilizing its empty return rail cars.

Another important driver for securing this marketing arrangement is the security of access to the world's largest market for heavy crude. Given recent regulatory delays around additional pipeline capacity to accommodate growing bitumen volumes from Alberta, the Company has now secured direct and immediate access into the Gulf Coast market. Because of these access issues, the Gulf Coast market for heavy crude currently trades at a premium to WTI, whereas Alberta-based blended bitumen and diluent ("dilbit") products arriving by pipeline into the Cushing, Okla., region of the U.S. are experiencing significant pricing discounts due to capacity constraints.

The rail and terminal arrangements described above have an average term of five years, with options for extension and expansion related to Southern Pacific's STP-McKay Phase 1 Expansion and Phase 2 plans. Expansion opportunities being discussed include the construction of a pipeline system to the CN Lynton terminal or building a rail spur to the STP-McKay plant site. Either option would remove the trucking component and further reduce diluent costs. While the Gulf Coast is the initial target market, the details within the arrangement provide Southern Pacific with the flexibility to deliver its bitumen to other North American markets or to export terminals along the west coast.

STP-McKay Phase 1 Expansion and Phase 2 Update

On May 10, 2012, Southern Pacific announced plans to expand STP-McKay 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 identified a unique opportunity to expand the existing STP-McKay Phase 1 central process facilities 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 entire expansion should fit comfortably within the existing Phase 1 central process facility site, making this expansion both cost effective and environmentally responsible.

Southern Pacific continues to work on the regulatory approval process for the Phase 1 Expansion and Phase 2 of STP-McKay. Throughout the summer, the Company has been preparing its responses to the first round of Supplementary Information Requests (SIRs) requested by the Alberta regulators. The responses should be completed by mid September, which should keep the approval process on track for approval by the fourth quarter of 2013.

Results of Operations

Production

	Three Months Ended June 30,			Twelve Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Heavy oil (bbl/day)	**3,402**	4,868	(30%)	**3,639**	4,230	(14%)
Natural gas (mcf/day)	**11**	284	(96%)	**52**	221	(76%)
Total (boe/day)	**3,404**	4,915	(31%)	**3,648**	4,267	(15%)

Heavy oil production for the quarter ended June 30, 2012 averaged 3,402 bbl/day, a decrease of 30% over the same period in 2011. The change in volumes is due to timing of new wells and regulatory delays; the previous year's reported quarter was unusually high because a new pad (Phase H) had just come on stream in the quarter, whereas in this year, the most recent pad was placed on stream in January. Natural gas production was lower quarter over quarter as the Company sold its remaining conventional assets in July 2011.

For the twelve months ended June 30, 2012 the heavy oil production averaged 3,639 bbl/day, a 14% decrease from the same period in 2011. The year over year decrease is attributable in part to a bi-annual turnaround at the STP-Senlac plant that occurred in September 2011, and also the timing of new SAGD well pads. Two pads (5 SAGD well pairs) were added in fiscal 2011, whereas only one pad (3 SAGD well pairs) was added in fiscal 2012. The natural gas declines are the result of the sale of non-core conventional assets in the first quarter of fiscal 2012.

Product Prices

	Three Months Ended June 30,			Twelve Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Heavy oil ($ per bbl)	**56.51**	69.13	(18%)	**63.51**	60.51	5%
Natural gas ($ per mcf)	**2.17**	3.69	(41%)	**3.16**	3.71	(15%)
Combined average ($ per boe)	**56.49**	68.68	(18%)	**63.41**	60.17	5%

The heavy oil price received by Southern Pacific was $56.51 per bbl for the three months ended June 30, 2012, 18% lower than the same quarter in the prior year. The decrease in the heavy oil price for the fourth quarter of 2012 is largely attributable to the decrease in the WTI crude oil price and 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.

For the twelve months ended June 30, 2012 the heavy oil price increased 5% over the prior year to $63.51 per bbl. The increase was due to higher WTI pricing offset with higher blending costs.

Operating Netbacks

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ per boe)	2012	2011	Change	2012	2011	Change
Combined average	**56.49**	68.68	(18%)	**63.41**	60.17	5%
Royalties	**(10.48)**	(12.73)	(18%)	**(10.82)**	(10.83)	0%
Operating costs	**(11.05)**	(8.91)	24%	**(10.66)**	(10.07)	6%
Operating netback	**34.96**	47.04	(26%)	**41.93**	39.27	7%

Operating netbacks for the quarter and twelve months ended June 30, 2012 decreased by 26% and increased by 7% respectively, over the same periods in the prior year. The decrease for the quarter ended June 30, 2012 is primarily due to lower average combined product prices and increased operating costs. The increase for the twelve months ended June 30, 2012 is primarily due to the higher average combined product prices received offset in part by higher operating costs.

Oil and Gas Revenue

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands)	2012	2011	Change	2012	2011	Change
Heavy oil	**17,493**	30,626	(43%)	**84,588**	93,427	(9%)
Natural gas	**2**	95	(98%)	**63**	300	(79%)
Total oil and gas revenue	**17,495**	30,721	(43%)	**84,651**	93,727	(10%)

Total oil and gas revenue for the quarter and twelve months ended June 30, 2012 was $17.5 million and $84.7 million respectively. The decrease for the quarter ended June 30, 2012 of 43% is due to lower production volumes and realized heavy oil price. The decrease for the twelve months ended June 30, 2012 of 10% is due to lower 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 twelve months ended June 30, 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

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands)	2012	2011	Change	2012	2011	Change
Unrealized (loss) gain	**4,731**	5,971	(21%)	**6,914**	297	2,228%
Realized gain	**1,181**	(174)	779%	**2,313**	(11)	21,127%
Risk management contracts	**5,912**	5,797	2%	**9,227**	286	3,126%

For the quarter and twelve months ended June 30, 2012, Southern Pacific recorded an unrealized gain on risk management contracts of $4.7 million and $6.9 million respectively, compared to an unrealized gain of $6.0 million and $0.3 million for the same periods in 2011. The unrealized gains for the quarter and fiscal 2012 are mainly attributable to the oil collars and the fixed oil differential contracts due to the change in WTI.

The realized gain of $1.2 million for the quarter ended June 30, 2012 is attributable to the fixed oil differential contracts and the oil collars due to the change in WTI. For the twelve months ended June 30, 2012 the gain of $2.3 million is mainly related to oil collars, differential hedges and the foreign exchange contracts. The realized gains or losses on the risk management contracts represent actual cash received or paid by Southern Pacific as its contracted 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	Three Months Ended June 30,			Twelve Months Ended June 30,		
% and per boe)	2012	2011	Change	2012	2011	Change
Royalties	**2,981**	5,169	(42%)	**13,035**	15,274	(15%)
Provincial resource surcharges	**264**	526	(50%)	**1,412**	1,588	(11%)
	3,245	5,695	(43%)	**14,447**	16,862	(14%)
% of oil and gas revenue	**18.5%**	18.5%	-	**17.1%**	18.0%	(5%)
Per boe	**$10.48**	$12.73	(18%)	**$10.82**	$10.83	-

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 June 30, 2012 were $3.2 million, compared to $5.7 million for the same quarter in 2011. The royalties represented 18.5% of total petroleum and natural gas revenue which is comparable to the same quarter in 2011 at 18.5%. On an absolute basis the royalties are lower due to decreased revenues.

Royalties for the twelve months ended June 30, 2012 were $14.4 million, compared to $16.9 million in 2011, which represented 17.1% and 18.0% respectively of the total petroleum and natural gas revenue. On an absolute basis the royalties are lower due to decreased revenues.

Operating Costs

($ thousands except for per boe)	Three Months Ended June 30, 2012	2011	Change	Twelve Months Ended June 30, 2012	2011	Change
Other operating costs	**1,912**	2,166	(12%)	**9,053**	9,171	(1%)
Natural gas costs	**1,509**	1,818	(17%)	**5,182**	6,509	(20%)
Operating costs	**3,421**	3,984	(14%)	**14,235**	15,680	(9%)
Per boe	**$11.05**	$8.91	24%	**$10.66**	$10.07	6%

Other operating costs for the quarter and twelve months ended June 30, 2012 decreased by 12% and 1% respectively, compared to the same periods in 2011. The decrease in the quarter is attributable to lower production volumes. For the twelve months ended June 30, 2012 and 2011, the decrease is due to lower production volumes.

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 twelve months ended June 30, 2012 the natural gas costs decreased by 17% and 20% respectively compared to the same periods in 2011. The decrease is the result of lower natural gas prices.

In total, operating costs were $3.4 million for the quarter ended June 30, 2012, compared to $4.0 million for the same quarter in 2011. For the twelve months ended June 30, 2012 total operating costs at $14.2 million were 9% less than the prior year. On a per barrel basis, for the quarter ended June 30, 2012 the operating costs increased to $11.05 from $8.91 in the prior quarter of 2011 as a significant component of operating costs are fixed in nature. For the twelve months ended June 30, 2012 the operating costs are comparable at $10.66 versus $10.07 in 2011.

Exploration and Evaluation Expenses

Exploration and evaluation expenses for the fourth quarter 2012 were $nil compared to $0.1 million for the fourth quarter 2011. For the twelve months ended June 30, 2012 the exploration and evaluation expenses were $nil compared to $0.5 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

($ thousands except for per boe)	Three Months Ended June 30, 2012	2011	Change	Twelve Months Ended June 30, 2012	2011	Change
General and administrative expenses	**3,346**	3,187	5%	**11,798**	9,527	24%
Per boe	**$10.80**	$7.12	52%	**$8.84**	$6.12	44%

General and administrative expenses for the quarter ended June 30, 2012 were 5% higher compared to the same period in 2011. The increase for the quarter and twelve months ended June 30, 2012 is due to additional personnel hired and administration costs required to maintain the corporation's continued operations with addition of the STP-McKay Phase 1 Thermal Project.

Finance Expenses

($ thousands except for per boe)	Three Months Ended June 30, 2012	2011	Change	Twelve Months Ended June 30, 2012	2011	Change
Interest and financing	**159**	143	11%	**597**	326	83%
Accretion	**(7)**	44	(116%)	**49**	93	(47%)
	152	187	(19%)	**646**	419	54%
Per boe	**$0.49**	$0.42	17%	**$0.48**	$0.27	80%

Interest and financing expenses for the quarter and twelve months ended June 30, 2012 were higher than the previous period by 11% and 83% respectively, due to the increase in standby fees related to the new credit facility. Interest costs of $10.0 million and $39.8 million are capitalized as part of STP-McKay Phase 1 for the quarter and twelve months ended June 30, 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 ($7,000) for the quarter ended June 30, 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 $41.4 million and will be accreted up to the estimated undiscounted liability of $88.6 million over the remaining economic life of the Company's assets.

Depletion and Depreciation

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands except for per boe)	2012	2011	Change	2012	2011	Change
Depletion and depreciation	**5,623**	8,171	(31%)	**25,055**	30,420	(18%)
Per boe	**$18.16**	$18.27	(1%)	**$18.77**	$19.53	(4%)

Depletion and depreciation expense for the quarter ended June 30, 2012 decreased over the prior period in 2011 by 31% on an absolute basis and 1% on a per boe basis. The decrease was the result of decreased production. For the twelve months ended June 30, 2012 and 2011 the decrease in the depletion was also a result of decreased production.

The depletion on petroleum and natural gas properties is booked on a quarterly basis. For the quarter ended June 30, 2012, $688.0 million in oil sands properties (STP-McKay Phase 1) were excluded from the depletion calculation and $120.7 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 June 30,			Twelve Months Ended June 30,		
($ thousands)	2012	2011	Change	2012	2011	Change
Foreign Exchange loss (gain)	**$4,195**	($429)	(1,078%)	**$5,719**	($1,102)	(619%)

For the three and twelve months ended June 30, 2012, the Company had a foreign exchange loss of $4.2 million and $5.7 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 June 30, 2012 the foreign exchange loss, primarily related to the U.S. debt, was the result of a weakening Canadian dollar from $0.999 CAD/USD at March 31, 2012 to $1.019 CAN/USD at June 30, 2012. For the twelve months ended June 30, 2012 the foreign exchange loss, also primarily related to the U.S. debt, was the result of a weakening Canadian dollar which moved from $0.964 CAN/USD at June 30, 2011 to $1.019 CAN/USD at June 30, 2012.

Stock-Based Compensation

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands except for per boe)	2012	2011	Change	2012	2011	Change
Stock-based compensation	**946**	756	25%	**3,802**	2,810	35%
Per boe	**$3.05**	$1.69	80%	**$2.85**	$1.80	58%

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 twelve months ended June 30, 2012 stock-based compensation was $0.9 million, and $3.8 million compared to $0.8 million and $2.8 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 $2.4 million and a $8.6 million deferred tax expense for the quarter and twelve months ended June 30, 2012 compared to a $3.3 million and a $3.7 million deferred tax expense for the comparative quarter and twelve months ended June 30, 2011.

The Company estimates it has approximately $712.2 million in tax pools before the deferred partnership income allocation as at June 30, 2012. Deferred partnership income is estimated to be $12.6 million, which would reduce the tax pools to $699.6 million. Both balances include $195.8 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 2013.

Net Income

Southern Pacific recorded net income of $0.1 million, or $0.00 per share, for the quarter ended June 30, 2012, compared to net income of $7.5 million, or $0.02 per share, for same quarter in 2011. For the twelve months ended June 30, 2012 the Company recorded net income of $11.2 million, or $0.03 per share, compared to the net income of $14.9 million, or $0.04 per share, in the prior period.

Cash From Operating Activities Before Changes In Non-Cash Working Capital

($ thousands except	Three Months Ended June 30,			Twelve Months Ended June 30,		
per boe and per share)	2012	2011	Change	2012	2011	Change
Cash from operating activities before changes in non-cash working capital	**8,481**	17,942	(53%)	**46,906**	51,872	(10%)
Per boe	**$27.38**	$40.11	(32%)	**$35.14**	$33.31	5%
Per share - basic	**$0.02**	$0.05	(60%)	**$0.14**	$0.16	(13%)
Per share - diluted	**$0.02**	$0.05	(60%)	**$0.14**	$0.15	(7%)

Cash from operating activities before changes in non-cash working capital were $8.5 million for the quarter and $46.9 million for the twelve months ended June 30, 2012, which is lower than the $17.9 million for the quarter and $51.9 million for the twelve months ended June 30, 2011. The decrease for the quarter is attributable to lower production, lower commodity prices offset by lower royalties and operating costs. For the twelve months ended June 30, 2012, cash from operating activities before changes in non-cash working capital were lower due to lower production, lower commodity prices, higher G&A expenses offset by lower royalties and operating costs.

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 twelve months ended June 30, 2012 and 2011 are summarized in the following table:

($ thousands)	Three Months Ended June 30, 2012	2011	Twelve Months Ended June 30, 2012	2011
McKay – Phase 1 and 2	**$50,671**	$101,667	**$311,465**	$247,316
Senlac	**3,368**	5,464	**23,976**	16,455
Red Earth	**66**	1,860	**2,720**	2,009
Other Exploration	**(14)**	(52)	**87**	142
Corporate	**1,680**	(65)	**2,700**	902
Conventional	**(200)**	(4,000)	**(2,385)**	(3,740)
Acquisition	**-**	-	**-**	19,168
Total	**$55,571**	$104,874	**$338,563**	$282,252

For the quarter and twelve months ended June 30, 2012 the Company incurred $55.6 million and $338.6 million in capital expenditures. For STP-McKay Phase 1 and 2 the total expenditures for the quarter and twelve months ended June 30, 2012 of $50.7 million and $311.5 million include capitalized interest of $10 million and $39.8 million respectively. The McKay capital expenditures for the three months ended June 30, 2012 decreased over the prior period in 2011 because the project is near completion and spending is winding down. The increase in the McKay capital expenditures for the twelve months ended June 30, 2012 over the prior period in 2011 is because the expenditures related to the building of the SAGD facility didn't commence until September of 2010. Senlac capital costs are down 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. 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 twelve months ended June 30, 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 $2.4 million for the twelve months ended June 30, 2012. The acquisition capital for the twelve months ended June 30, 2011 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 twelve months ended June 30, 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 June 30, 2012 Southern Pacific had a working capital deficiency of $7.0 million. The Company has a $30.0 million demand revolving operating credit facility with a syndicate of banks with $0.8 million of letters of credit issued and outstanding at June 30, 2012. 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)	June 30, 2012
Bank lines available	**$29,220**
Working capital deficiency	**(7,026)**
Capital resources available	**$22,194**

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 $22.2 million, budgeted funds from operations over the next 12 months and recently announced $75 million equity financing.

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 September 24, 2012:

Type	Contract Term	Volume	Price
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-$105.00
Oil collar (WTI)	Jan 1, 2013 to Dec 31, 2013	1,000 bbl/day	US$95.00-$105.25
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 September 24, 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 its SAGD 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
Natural gas fixed purchase (AECO)	Jan 1, 2013 to Dec 31, 2013	1,500 gj/day	$3.025
Natural gas fixed purchase (AECO)	Jan 1, 2013 to Dec 31, 2013	1,000 gj/day	$3.01
Natural gas fixed purchase (AECO)	Jan 1, 2013 to Dec 31, 2013	1,000 gj/day	$2.88
Natural gas fixed purchase (AECO)	Jan 1, 2013 to Dec 31, 2013	1,000 gj/day	$2.95

Leases

At June 30, 2012 the Company is committed to annual lease payments under the terms of a lease for its head office space, other equipment and marketing agreements:

($ thousands)	June 30, 2012	June 30, 2011
2013	**$5,120**	$409
2014	**14,228**	409
2015	**14,043**	239
2016	**13,710**	-
2017	**12,588**	-
Thereafter	**13,957**	-
Total	**$73,646**	$1,057

Capital

At June 30, 2012, as part of normal operations relating to the construction of STP-McKay Phase 1, the Company entered into a total of $6.2 million in capital commitments to be paid over the next year.

Principal Payments

At June 30, 2012, the Company's required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

($ thousands)	Term loan	Convertible debentures	Total
2013	$2,803	$-	**$2,803**
2014	2,803	-	**2,803**
2015	2,803	-	**2,803**
2016	267,640	172,500	**440,140**
Total	$276,049	$172,500	**$448,549**

Off Balance Sheet Arrangements

Southern Pacific has not entered into any off balance sheet arrangements at June 30, 2012.

Transactions With Related Parties

The Company had transactions with its related parties which include key management personnel. Key management personnel include directors and executive officers of the Company.

	Twelve Months Ended June 30,		
($ thousands)	2012	2011	Change
Salaries and benefits	**$3,061**	$1,858	65%
Share based compensation	**2,360**	1,446	63%
Total compensations paid or payable	**$5,421**	$3,304	64%

During 2012, the Company incurred legal costs of $0.8 million (2011 - $0.6 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, $0.1 million were included in accounts payable at June 30, 2012 (2011 – nil).

Subsequent Event

On September 10, 2012 the Company entered into an agreement with a syndicate of underwriters to sell, on a bought deal basis, 51.7 million common shares of the Company at a price of $1.45 per common share for total gross proceeds of approximately $75.0 million. In addition, the Company has granted the underwriters an over-allotment option to acquire an additional 7.8 million common shares at a price of $1.45 per common share for additional gross proceeds of $11.0 million. The offering is scheduled to close on or about September 28, 2012.

Outstanding Securities

Common Shares, Options and Warrants

There were 28,200 and 2.0 million common shares issued during the quarter and twelve months ended June 30, 2012 respectively, at a weighted average exercise price of $1.00 and $0.68 per share respectively, from the exercise of stock options. In addition, 0.2 million warrants were exercised in the twelve months ending June 30, 2012 at a weighted average exercise price of $1.01.

As at June 30, 2012, 27.8 million stock options were outstanding with an average exercise price of $1.21 and nil warrants were outstanding. At September 24, 2012, the Company has 341.3 million common shares outstanding, 27.8 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)	06/30/12 (1)	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)
Production (boe/d)	3,404	4,156	3,249	3,784	4,915	3,664	4,359	4,123
Oil and gas revenue	$17,495	$24,399	$21,994	$20,769	$30,721	$18,791	$23,514	$20,701
Combined average price ($/boe)	$56.49	$64.52	$73.54	$59.65	$68.68	$56.98	$58.63	$54.58
Royalties ($/boe)	$10.48	$11.48	$10.86	$10.38	$12.73	$9.93	$11.31	$8.85
Operating costs ($/boe)	$11.05	$8.63	$11.26	$12.02	$8.91	$11.59	$10.59	$9.56
Operating netback ($/boe)	$34.96	$44.41	$51.42	$37.25	$47.04	$35.46	$36.73	$36.17
G&A expense ($/boe)	$10.80	$6.60	$12.55	$6.33	$7.12	$7.96	$6.14	$3.30
Cash from operating activities before changes in non-cash working capital	$8,481	$16,502	$11,248	$10,675	$17,942	$9,322	$12,268	$12,340
Per share - basic	$0.02	$0.05	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04
- diluted	$0.02	$0.05	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04
Net income (loss)	$70	$11,553	$224	($697)	$7,474	$111	$5,506	$1,795
Per share - basic	$0.00	$0.03	$0.00	($0.00)	$0.02	$0.00	$0.02	$0.01
- diluted	$0.00	$0.03	$0.00	($0.00)	$0.02	$0.00	$0.02	$0.01
Capital expenditures	$55,571	$78,117	$98,972	$105,903	$104,874	$96,096	$74,203	$7,079

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

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 June 30, 2012 the CEO and CFO have 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 20 of the consolidated financial statements.

Significant IFRS impacts on financial reporting

The IFRS accounting policies are set forth in Note 3 of the audited consolidated financial statements for the year ended June 30, 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 audited consolidated financial statements under Note 20.

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 and 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 $155.6 million at June 30, 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 $4.0 million at June 30, 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 June 30, 2011 a rate of 3.11% was used with an increase to the decommissioning liability of $12.1 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 June 30, 2011 the decrease to contributed surplus was $0.3 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 $5.0 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 $15.1 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.

Non-GAAP Measure

This MD&A includes references to certain financial measures, as described below, which do not have standardized meanings prescribed by IFRS. Because this measure is commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The Company uses this measure to evaluate its performance. Investors are cautioned that this non-GAAP measure should not be construed as an alternative to the measure calculated in accordance with IFRS as, given its non-standardized meaning, it is unlikely to be comparable to similar measures presented by other issuers. This non-GAAP measure should not be considered an alternative to, or more meaningful than net income as determined in accordance with IFRS as an indicator of the Company's performance. The term "operating netback" is defined as petroleum and natural gas sales less royalties and less operating expenses. The following is a reconciliation from the nearest IFRS measurement:

	Three Months Ended June 30,		Twelve Months Ended June 30,	
($ thousands)	**2012**	**2011**	**2012**	**2011**
Production revenue, net of royalties	**$14,251**	$25,362	**$71,750**	$77,349
Other income	**(1)**	(336)	**(1,546)**	(484)
Operating costs	**(3,421)**	(3,984)	**(14,235)**	(15,680)
Operating netback	**$10,829**	$21,042	**$55,969**	$61,185

Additional GAAP Measure

This MD&A includes references to a certain additional GAAP measure, as described below, which is additional to the minimal prescribed disclosure by IFRS. Because this measure is commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The Company uses this measure to evaluate its performance and therefore defines it as an additional GAAP measure. The term "Cash from operating activities before changes in non-cash working capital" is disclosed in the cash flow as the cash flow from operating activities before the change in non-cash working capital and decommissioning expenditures and should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of performance. The Company's determination of cash from operating activities before changes in non-cash working capital may not be comparable to that reported by other companies.

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.

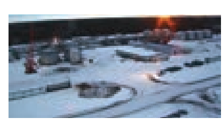
With respect to the forward-looking statements listed above and contained in this MD&A, the Company has made assumptions regarding, among other things:

- 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, 2012, 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 24, 2012 at www.sedar.com and available on Southern Pacific's website at www.shpacific.com. Please refer to this document for more information.

Management's Responsibility

To the Shareholders of Southern Pacific Resource Corp.:

The accompanying financial statements are the responsibility of Management. The financial statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards ('IFRS') and include certain estimates that reflect Management's best judgments.

In discharging its responsibilities for the integrity and fairness of the financial statements, management designs and maintains the necessary accounting systems and related internal controls to provide reasonable assurance that transactions are authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

The Board of Directors and Audit Committee are composed primarily of Directors who are neither management nor employees of the Company. The Board is responsible for overseeing management in the performance of its financial reporting responsibilities and for approving the financial information included in the financial statements. The Audit Committee has the responsibility of meeting with management and external auditors to discuss the internal controls over the financial reporting process, auditing matters and financial reporting issues. The Committee is also responsible for recommending the appointment of the Company's external auditors.

Deloitte and Touche LLP, an independent firm of Chartered Accountants, is appointed by the shareholders to audit the financial statements and report directly to them; their report follows. The external auditors have full and free access to, and are available to meet periodically and separately with, the Board and management to discuss their audit findings.

Byron Lutes
Chief Executive Officer
September 24, 2012

Howard Bolinger
Chief Financial Officer
September 24, 2012

Independent Auditor's Report

To the Shareholders of Southern Pacific Resource Corp.:

We have audited the accompanying consolidated financial statements of Southern Pacific Resource Corp., which comprise the consolidated statements of financial position as at June 30, 2012 and 2011 and July 1, 2010, and the consolidated statements of comprehensive income, consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years ended June 30, 2012 and 2011, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Southern Pacific Resource Corp. as at June 30, 2012 and 2011 and July 1, 2010, and its financial performance and its cash flows for the years ended June 30, 2012 and 2011 in accordance with International Financial Reporting Standards.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta
September 24, 2012

Consolidated Statements of Financial Position

Stated in thousands of Canadian dollars

As at	June 30, 2012	June 30, 2011	July 1, 2010
Assets			
Current assets			
Cash and cash equivalents (notes 5 and 8)	**$ 20,590**	$ 322,927	$ 63,505
Trade and other accounts receivable (note 14)	**13,442**	13,091	7,377
Inventory	**187**	-	-
Prepaid expenses and deposits	**671**	1,157	232
Risk management contracts (note 14)	**7,484**	570	273
	42,374	337,745	71,387
Non-current assets			
Exploration and evaluation assets (note 6)	**94,559**	155,562	172,546
Property, plant and equipment (note 7)	**779,893**	385,580	105,264
	$ 916,826	$ 878,887	$ 349,197
Liabilities and Shareholders' Equity			
Current liabilities			
Trade and other accounts payable	**$ 46,597**	$ 75,574	$ 11,458
Current portion of long term debt (note 8)	**2,803**	2,652	-
	49,400	78,226	11,458
Non-current liabilities			
Long term debt (note 8)	**400,040**	379,148	-
Decommissioning liability (note 9)	**41,375**	22,127	10,185
Deferred tax liability (note 10)	**54,769**	46,197	38,761
	545,584	525,698	60,404
Shareholders' Equity			
Share capital (note 11)	**309,287**	306,499	283,603
Equity component of convertible debentures (note 8)	**25,284**	25,284	-
Contributed surplus (note 12)	**28,508**	24,393	23,064
Retained earnings (deficit)	**8,163**	(2,987)	(17,874)
	371,242	353,189	288,793
	$ 916,826	$ 878,887	$ 349,197

Commitments (note 16)
Subsequent event (note 19)

See accompanying notes to the consolidated financial statements.

Signed "*David M. Antony*"
David M. Antony, Director

Signed "*Kenneth N. Cullen*"
Kenneth N. Cullen, Director

Consolidated Statements of Comprehensive Income

Stated in thousands of Canadian dollars except per share amounts

For the year ended June 30	2012	2011
Revenues and Other Income		
Petroleum revenue, net of royalties (note 17)	**$ 71,750**	$ 77,349
Gain on risk management contracts (note 14)	**9,227**	286
	80,977	77,635
Expenses		
Operating	**14,235**	15,680
Exploration and evaluation	**-**	456
General and administrative	**11,798**	9,527
Finance (note 18)	**646**	419
Stock based compensation	**3,802**	2,810
Foreign exchange loss (gain)	**5,719**	(1,102)
Depletion and depreciation	**25,055**	30,420
Impairment	**-**	4,461
	61,255	62,671
Other		
Gain on acquisition (note 4)	**-**	3,585
Income before income taxes	**19,722**	18,549
Deferred income tax expense (note 10)	**8,572**	3,662
Net income and comprehensive income for the year	**$ 11,150**	$ 14,887
Earnings per share - basic and diluted (note 11)	**$ 0.03**	$ 0.04

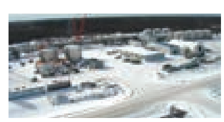
See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

Stated in thousands of Canadian dollars

	2012	2011
Share Capital (note 11)		
Balance, beginning of year	**$ 306,499**	$ 283,603
Exercise of options	**2,628**	2,775
Exercise of warrants	**160**	-
Share issue costs	**-**	(32)
Acquisition of North Peace	**-**	20,153
Balance, end of year	**309,287**	306,499
Equity Component of Convertible Debentures (note 8)		
Balance, beginning and end of year	**25,284**	25,284
Contributed Surplus (note 12)		
Balance, beginning of year	**24,393**	23,064
Options exercised	**(1,268)**	(1,481)
Stock-based compensation	**5,383**	2,810
Balance, end of year	**28,508**	24,393
Retained Earnings (Deficit)		
Balance, beginning of year	**(2,987)**	(17,874)
Net income for the year	**11,150**	14,887
Balance, end of year	**8,163**	(2,987)
Shareholders' Equity	**$ 371,242**	$ 353,189

See accompanying notes to the consolidated financial statements.



Consolidated Statements of Cash Flows

Stated in thousands of Canadian dollars

For the year ended June 30	2012	2011
Cash provided by (used in)		
Operating activities:		
Net income	**$ 11,150**	$ 14,887
Adjustments for:		
Depletion and depreciation	**25,055**	30,420
Impairment	**-**	4,461
Finance expense (note 18)	**49**	93
Exploration and evaluation	**-**	456
Unrealized loss (gain) on foreign exchange (note 14)	**5,192**	(1,035)
Unrealized gain on risk management contracts (note 14)	**(6,914)**	(297)
Stock based compensation	**3,802**	2,810
Deferred taxes (note 10)	**8,572**	3,662
Gain on acquisition (note 4)	**-**	(3,585)
Cash from operating activities before changes in non-cash working capital	**46,906**	51,872
Change in non-cash operating working capital	**(748)**	(7,656)
Decommissioning expenditures (note 9)	**-**	(283)
Cash flows from operating activities	**46,158**	43,933
Financing activities:		
Issuance of common shares, net of share issuance costs (note 11)	**1,520**	1,263
Issuance of long term debt, net of transaction costs	**-**	421,796
Repayment of long-term debt	**(2,797)**	(1,335)
Cash flows from financing activities	**(1,277)**	421,724
Investing activities:		
Exploration and evaluation expenditures (note 6)	**(5,521)**	(29,453)
Net property, plant and equipment expenditures (note 7)	**(324,997)**	(234,311)
Petroleum and natural gas dispositions (note 7)	**1,783**	-
Petroleum and natural gas acquisitions (note 4)	**-**	72
Net change in non-cash investing working capital	**(28,281)**	64,415
Cash flows from investing activities	**(357,016)**	(199,277)
Net (decrease) increase in cash and cash equivalents	**(312,135)**	266,380
Foreign exchange gain (loss) on cash balances (note 14)	**9,798**	(6,958)
Cash and cash equivalents, beginning of period	**322,927**	63,505
Cash and cash equivalents, end of period	**$ 20,590**	$ 322,927

Supplementary cash flow information		
Finance costs paid and capitalized (note 7)	**$ 39,761**	$ 18,745

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Years ended June 30, 2012 and 2011

1. **Incorporation and nature of operations:**

   Southern Pacific Resource Corp., and 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 consolidated financial statements (the "financial statements") are prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company's transition date to IFRS was July 1, 2010 and results for the year ended June 30, 2011 have been restated from the previous Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS. The transition to IFRS resulted in changes to the Company's accounting policies and these are disclosed in Note 20 along with reconciliations of the financial statements under GAAP to their IFRS values. These financial statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards".

   The policies applied in these financial statements are based on IFRS issued and outstanding as of September 24, 2012, the date the Board of Directors approved the financial statements.

   (b) **Basis of measurement**

   These financial statements have been prepared on the historical cost basis except for the revaluation of derivative financial 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 and the related depletion.

Amounts recorded for depletion, impairment calculations and amounts used in the determination of deferred 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 certain 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 applicable to the Companies operations 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:

(a) Principles of consolidation:
The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. All intercompany transactions and balances have been eliminated upon consolidation. Operations of acquired businesses are included from their respective acquisition dates.

(b) Cash and cash equivalents:
Cash and cash equivalents include cash and term deposits with original maturities of three months or less.

(c) Inventories:
Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Net realizable value is the estimated selling price less applicable selling expenses.

(d) Exploration and evaluation assets ("E&E"):
E&E expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred and recorded in the statement of comprehensive income.

Costs directly associated with the exploration and evaluation of oil and gas reserves are initially capitalized. The costs included are those expenditures where technical feasibility and commercial viability have not yet been determined and include costs such as land rights in areas with no recoverable assigned reserves, geological and geophysical costs, and the costs of drilling exploration wells.

E&E costs are classified as intangible assets and are not depleted. E&E assets are transferred to property, plant, and equipment when they are determined to meet technical feasibility and commercial viability. If reserves are not found in commercial quantities then the capitalized costs are assessed for impairment and any impairment required is charged to the statement of comprehensive income.

The carrying amount of E&E assets is tested for impairment at least annually, when facts or circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount and upon transfer to property, plant and equipment.

(e) Property, plant and equipment:

Property, plant and equipment is initially recognized at cost which represents all costs directly associated with the development of oil and natural gas reserves where technical feasibility and commercial viability is determined. Costs include drilling of development wells, tangible costs of facilities and infrastructure construction, proved property acquisitions, decommissioning liabilities, and transfers of successful E&E assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use. The Company also capitalizes expenses, including wages, salaries, benefits and other office costs that are directly attributable to bringing qualifying assets into operation.

Depletion and depreciation of petroleum and natural gas properties is calculated using the unit of production method based upon the production volumes, before royalties, in relation to the recoverable petroleum and natural gas reserves as estimated by independent engineers. In determining costs subject to depletion, the Company includes estimated future costs to be incurred in developing recoverable reserves and excludes residual value. For depletion purposes, natural gas volumes are converted to equivalent volumes based upon a relative energy content of six thousand cubic feet of natural gas to one barrel of oil.

Where significant parts of an item of property, plant and equipment have different lives than the oil and gas reserves, they are accounted for as separate items (major components) and depreciated over the life of the component.

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as capital only when they increase the future economic benefits of the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing recoverable reserves and enhancing production from such reserves. All other expenditures are recognized in comprehensive income as incurred.

Other capital assets are recorded at cost. The Company provides for amortization using the declining balance method for computer equipment and software, office equipment and furniture at rates designed to amortize the cost over their estimated useful lives ranging from 30% to 50%.

Property plant and equipment are grouped into CGUs and are reviewed quarterly for indicators of impairment. If these indicators suggest that an impairment may exist, an impairment test is performed in which the carrying amounts of these assets are written down to their recoverable amount, which is the higher of fair value less costs to sell ("FVLCS") and value-in-use ("VIU"). In determining FVLCS recent market transactions are taken into account and if these are not available then a valuation model is used. The discounted cash flows used in the model are generally derived from information contained in the reserve report. VIU is determined by estimating the discounted cash flows expected from the continuing use of the asset.

Impairment losses recognized in prior periods are assessed at each reporting date for indications that the loss has decreased or no longer exists. The impairment loss can be reversed up to the original carrying value of the asset that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized. This reversal is recognized in the statement of comprehensive income.

When assets are sold, a gain or loss is calculated by comparing the disposal proceeds with the carrying amount of the asset. This gain or loss is recognized in the statement of comprehensive income.

(f) Revenue recognition:

Revenue associated with the production and sale of oil, natural gas and natural gas liquids owned by the Company is recognized when title passes to the customer and collectability is reasonably assured. Interest income is recognized when earned.

(g) Share based compensation:

Share options issued are accounted for in accordance with fair value accounting for share-based compensation. The associated share compensation expense is charged to the statement of comprehensive income with a corresponding increase to contributed surplus, over the vesting period of the option. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. The fair value of each stock option granted is estimated on the date of grant using a Black–Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. As the options are exercised, consideration paid, along with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. In the event that vested options expire, previously recognized compensation expense associated with such stock options is not reversed. All forfeited options are cancelled by the Company immediately, no stock based compensation is recorded on these options in future periods and any related unvested stock based compensation is reversed.

(h) Per share amounts:

Basic net earnings per share is calculated using the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the weighted average number of common and common equivalent shares outstanding during the period using the treasury stock method. This method assumes the proceeds from the exercise of dilutive options and warrants are used to purchase common shares at the weighted average market price during the period. Common equivalent shares consist of the incremental common shares issued upon the exercise of in the money stock options and warrants unless their effect is anti-dilutive.

(i) Foreign Currency Translation:

Transactions in foreign currencies are translated into Canadian dollars at exchange rates prevailing at the transaction dates. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Resulting exchange gains and losses are included in earnings.

(j) Income taxes:

Tax expense comprises current and deferred taxes. Tax expense is recognized in the statement of comprehensive income except when it relates to items recognized directly in other comprehensive income (loss) and equity, in which case the tax is also recognized in other comprehensive income (loss) and equity. Income tax assets and liabilities are presented separately in the consolidated balance sheet except where there is a right of set-off within fiscal jurisdictions and an intention to settle such balances on a net basis.

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

The Company follows the liability method of accounting for deferred income taxes. Under this method, deferred income tax assets and liabilities are recorded based on the temporary differences between the carrying amount of the balance sheet items and their corresponding tax bases. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. In addition, the future benefits of income tax assets, including unused tax losses, are recognized, to the extent that it is probable that such future benefits will ultimately be realized. Deferred income tax assets and liabilities are measured using substantively enacted tax rates and laws expected to apply when the differences are either reversed or realized.

(k) Joint interest operations:
A portion of the Company's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

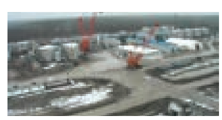
(l) Business combinations:
Business combinations are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the statement of comprehensive income. The associated transaction costs are expensed when incurred.

(m) Financial instruments:
A financial instrument is any contract that gives rises rise to a financial asset of one entity and a financial liability or equity instrument to another. Upon initial recognition all financial instruments, including derivatives, are recognized on the statement of financial position at fair value. Subsequent measurement is then based on financial instruments being classified into one of the following five categories: 1) loans and receivables, 2) assets held-to-maturity, 3) assets available-for-sale, 4) other financial liabilities, and 5) fair value through profit or loss. Financial instruments classified as fair value through profit or loss or available-for-sale items as a result of initial adoption are measured at fair value. Gains or losses on subsequent measurement of fair value through profit or loss are recognized in net income, while gains and losses on subsequent measurement of available-for-sale items are recognized as an adjustment to other comprehensive income.

At June 30, 2012, the Company's financial instruments include cash and cash equivalents, trade and other accounts receivables, risk management contracts, trade and other accounts payables, long term debt and convertible debentures. Net gains and losses arising from changes in fair value are recognized in net income upon derecognition or impairment. Cash and cash equivalents, trade and other accounts receivable are measured at amortized cost consistent with the "loans and receivables" classification. Loans and receivables are subsequently measured at their amortized cost, using the effective interest method. Under this method, estimated future cash receipts are discounted over the asset's expected life, or other appropriate period, to its net carrying value. Trade and other accounts payable, long term debt, and the liability portion of convertible debentures are measured at amortized cost using the effective interest method, consistent with the "other financial liabilities" classification. Equity instruments are recorded at the proceeds received with direct issue costs, net of related income taxes, deducted. For classifications other than "fair value through profit or loss", the transaction costs are netted against the carrying value of the instrument.

The Company has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting. As a result, all financial derivative contracts are classified as "fair value through profit and loss" and recorded on the statement of financial position at fair value at each reporting date. Gains and losses on these contracts are recognized in net income. Attributable transaction costs are recorded in the statement of comprehensive income.

Embedded derivatives are separated from the host contract and accounted for separately when all three of the following conditions are met: i) the economic characteristics and risks of the host contract and the embedded derivative are not closely related; ii) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and iii) the hybrid instrument is not measured at fair value with changes in fair value recognized in profit or loss. Changes in the fair value of the separated embedded derivative are recognized immediately in the statement of comprehensive income.



On initial recognition, the convertible debentures were classified into debt and equity components at fair value. The liability was valued at fair value using a valuation model that incorporates the redeemable option and this was deducted from the fair value of the convertible debenture as a whole to determine the value of the equity component. Subsequent to the initial recognition, the liability component is remeasured at amortized cost using the effective interest rate method. The equity component is not remeasured subsequent to initial recognition.

(n) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free interest rate. The accretion of the discount is recognized as finance cost. The carrying amounts of provisions are regularly reviewed and updated.

The Company records the fair value of a decommissioning obligation as a liability in the period in which it incurs a legal or constructive obligation associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the assets. The associated decommissioning costs are capitalized as part of the carrying amount of the long lived asset and are depleted using the unit of production method over estimated total proved and probable reserves. Subsequent to the initial measurement of the decommissioning obligation, the obligation is adjusted at the end of each period to reflect the passage of time (accretion), changes in the discount rate and changes in the estimated future cash flows underlying the obligation and is recognized within finance costs on the statement of comprehensive income. Actual abandonment restoration expenditures are charged to the decommissioning obligation as incurred, with any remainder recorded to earnings as a gain or loss.

(o) 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 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 financial assets and liabilities and is expected to be effective January 1, 2015. 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 IFRSs 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.

IFRS 7 "Financial Instruments: Disclosures" – This amendment provides disclosure requirements for the offsetting of a financial asset and financial liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013.

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.

IAS 32 "Financial Instruments: Presentation" – This amendment addresses the inconsistencies when applying the offsetting criteria outlined in this standard. These amendments clarify certain of the criteria required to be met in order to permit offsetting of financial assets and financial liabilities. The standard is required to be adopted retrospectively for periods beginning January 1, 2014.

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 financial statements.

4. Acquisition of North Peace Energy Corp.:

On November 23, 2010, the Company acquired all of the outstanding common shares of North Peace Energy Corp. ("North Peace") for total consideration of $20.2 million which was paid by the issuance of 14.1 million common shares. Additionally, $0.2 million of related transaction costs were included in general and administrative expense for the year ended June 30, 2011. The gain on acquisition is attributable to the excess of the fair value of assets acquired over the purchase price. The business combination was accounted for using the acquisition method of accounting.

As part of the acquisition, the Company was also obligated to issue shares upon exercise of share purchase warrants issued by North Peace. The North Peace warrants were convertible into warrants to purchase shares of the Company at an exchange ratio of 0.185, which resulted in 2.0 million warrants outstanding at an exercise price of $4.05. These warrants expired on December 23, 2010 unexercised. The fair value attributable to these warrants was nominal. The purchase price was allocated to the estimated fair values of the assets and liabilities acquired as follows:

Allocation of purchase price	
Petroleum and natural gas assets	$19,462
Net working capital (including cash of $72)	(647)
Deferred tax asset	5,555
Decommissioning liability	(632)
	$23,738

Calculation of purchase price	
Common shares issued (14.1 million shares)	$20,153
Gain on acquisition	3,585
	$23,738

5. Cash and cash equivalents:

Cash and cash equivalents are funds primarily intended for the STP-McKay Phase I project. As at June, 2012, US$19.1 million (June 30, 2011 - US$50 million) is held in a separate collateral escrow account (note 8(b)).

6. 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	5,885
Transferred to property, plant and equipment	(66,888)
Balance at June 30, 2012	**$94,559**

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 year ended June 30, 2012 the Company capitalized $0.9 million (June 30, 2011 – $nil) of directly attributable expenses and $nil of interest and debt service costs (June 30, 2011 – $nil) relating to oil sands exploration and evaluation.

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

	Oil and gas properties	Corporate	Total
Cost			
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	334,042	742	334,784
Change in decommissioning liabilities	19,479	-	19,479
Dispositions	(2,106)	-	(2,106)
Balance at June 30, 2012	**$832,766**	**$2,439**	**$835,205**
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	24,513	542	25,055
Dispositions	(323)	-	(323)
Balance at June 30, 2012	**$54,342**	**$970**	**$55,312**
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 June 30, 2012	**$778,424**	**$1,469**	**$779,893**

During the year ended June 30, 2012 the Company capitalized $2.1 million (June 30, 2011 - $0.6 million) of directly attributable expenses, $ 39.8 million (June 30, 2011 - $18.7 million) of interest costs and $8.9 million (June 30, 2011 – $3.9 million) of debt service costs relating to property, plant and equipment.

STP-McKay Phase 1 assets amounting to $688.0 million at June 30, 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 $120.7 million (June 30, 2011 $141.7 million) were included in property, plant and equipment. No impairment losses were recognized during the current year (2011 – $4.5 million).

8. Long-term debt:

	Note	June 30, 2012	June 30, 2011
Revolving credit facility (CDN$30 million)	(a)	**$-**	$-
Second lien term loan (US$270.9 million)		**276,049**	263,857
Financing transaction costs on second lien term loan		**(15,867)**	(15,867)
Amortization of financing costs		**3,967**	1,252
Less current portion of second lien term loan		**(2,803)**	(2,652)
	(b)	**261,346**	246,590
Convertible debentures (CDN$172.5 million)		**172,500**	172,500
Equity component of convertible debentures		**(36,225)**	(36,225)
Financing transaction costs on convertible debentures		**(6,339)**	(6,339)
Amortization of financing costs and equity		**8,758**	2,622
	(c)	**138,694**	132,558
Long-term debt		**$400,040**	$379,148

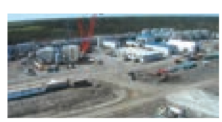
(a) Revolving credit facility (due January 7, 2014):

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 June 30, 2012, $0.8 million of letters of credit were issued and outstanding pursuant to the facility. As such, the Company has $29.2 million available under the facility. For the year ended June 30, 2012 $0.6 million (June 30, 2011 - $0.3 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 and start up 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 and start up 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 June 30, 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 year ended June 30, 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 8(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 June 30, 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 June 30, 2012.

As at June 30, 2012, US$19.1 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.

The term loan is translated into Canadian dollars at the period end exchange rate of $1 US = $1.0191 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
2013	$2,803	$ -	**$2,803**
2014	2,803	-	**2,803**
2015	2,803	-	**2,803**
2016	267,640	172,500	**440,140**
Total	$276,049	$172,500	**$448,549**

9. 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.

	2012	2011
Balance, beginning of year	**$22,127**	$10,185
Liabilities assumed on acquisition	**-**	632
Additions	**11,141**	11,551
Dispositions	**(1,159)**	-
Effect of change in estimates	**9,217**	(51)
Abandonment costs	**-**	(283)
Accretion	**49**	93
Balance, end of year	**$41,375**	$22,127

The total undiscounted amount of estimated cash flows required to settle the liability is $88.6 million (June 30, 2011 - $56.1 million), which has been discounted using a risk free rate of 2.2% 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 40 years.

10. Deferred taxes:

The deferred tax provisions differ from results which would be obtained had the Company applied the combined federal and provincial statutory rates of 27.5% (June 30, 2011 – 29.0%) to earnings. The reasons for these differences are as follows:

	2012	2011
Net income before income taxes	**$19,722**	$18,549
Statutory income tax rate	**27.5%**	29.0%
Expected income tax expense (recovery)	**5,424**	5,379
Differences resulting from:		
Stock-based compensation	**1,045**	815
Rate adjustments	**(782)**	(1,890)
Non-taxable loss (gain) on foreign exchange	**2,053**	(1,159)
Gain on acquistion	**-**	(1,040)
Other	**832**	1,557
Deferred income tax expense	**$8,572**	$3,662

The components of the net deferred income tax liability are as follows:

	June 30, 2012	June 30, 2011
Deferred income tax liability:		
Book value in excess of tax basis of assets	**$(98,453)**	$(66,934)
Non-capital losses	**50,897**	37,360
Decommissioning liability	**10,758**	5,874
Convertible debentures	**(7,483)**	(9,162)
Share issue costs	**958**	2,091
Deferred partnership income	**(12,573)**	(14,239)
Partnership deferral reduction	**2,171**	-
Unrealized gains (losses)	**902**	(1,039)
Risk management contracts	**(1,946)**	(148)
	$(54,769)	$(46,197)

The gross movement on the deferred tax account is as follows:

	2012	2011
Balance, beginning of year	**$(46,197)**	$(38,761)
Income statement charge	**(8,572)**	(3,662)
Credited directly to equity	**-**	(3,774)
Balance, end of year	**$(54,769)**	$(46,197)

The following provides the detail of the unrecognized deferred tax assets:

	June 30, 2012	June 30, 2011
Successor Canadian resource pools	**$28,267**	$35,665
Unused tax credits	**1,022**	1,022
	$29,289	$36,687

The unrecognized successor Canadian resource tax pools do not have a set expiration and the unused tax credits expire in 2029 and 2030.

As at June 30, 2012, the Company has total income tax pools of approximately $712.2 million (June 30, 2011 $456.3 million) including non-capital loss carryforwards prior to the allocation of deferred partnership income. Included in these tax pools are non-capital losses available to carry forward to future years of approximately $195.8 million (June 30, 2011 - $143.7 million) which expire, as follows:

	Amount
2014	**$522**
2015	**1,623**
2026	**1,816**
2027	**2,768**
2028	**5,900**
2029	**13,773**
2030	**45,370**
2031	**123,984**
Total	**$195,756**

11. Share capital:

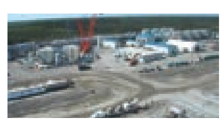
(a) Authorized:

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	2,775
Cancelled [(1)]	(42)	-
Share issue costs	-	(32)
Acquisition of North Peace	14,093	20,153
Balance, June 30, 2011	339,167	306,499
Exercise of options	2,008	2,628
Exercise of warrants	158	160
Cancelled [(1)]	(58)	-
Balance, June 30, 2012	**341,275**	**$309,287**

(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	7,708	1.35
Exercised	(2,008)	0.68
Forfeited	(974)	2.05
Expired	(975)	3.01
Balance, June 30, 2012	**27,750**	**$1.21**

The following table summarizes information about the stock options outstanding at June 30, 2012:

	Outstanding weighted average			Exercisable weighted average		
Range of exercise price	Options	Exercise price	Remaining life (years)	Options	Exercise price	Remaining life (years)
$0.10 - $0.15	1,320	$0.10	1.46	1,320	$0.10	1.46
$0.50 - $0.75	4,531	0.56	2.34	4,531	0.56	2.34
$0.77 - $1.15	3,098	0.98	1.97	2,674	0.97	1.78
$1.17 - $1.75	15,711	1.39	4.20	3,524	1.39	3.50
$1.76 - $1.92	2,865	1.89	1.36	2,365	1.90	0.75
$3.15 - $3.15	225	3.15	0.28	225	3.15	0.28
	27,750	**$1.21**	**3.19**	**14,639**	**$1.05**	**2.15**

The weighted average fair value of the options granted is estimated at $0.82 (June 30, 2011 – $0.70) on the dates of grant using a Black-Scholes option pricing model with the following assumptions:

	2012	2011
Risk free interest rate	**1.33%**	2.3%
Expected life in years	**4.97**	4.04
Expected volatility	**96.8%**	124.6%
Forfeiture rate	**1.63%**	0.58%
Dividend yield	**0%**	0%

(d) Warrants:

Warrant transactions are summarized as follows:

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

(e) Per share amounts:

	2012	2011
Net income	**$11,150**	$14,887
Weighted average common shares outstanding	**340,179**	331,902
Dilutive effect of stock options	**5,823**	6,932
Weighted average common shares outstanding - diluted	**346,002**	338,834
Earnings per share, basic	**$0.03**	$0.04
Earnings per share, diluted	**$0.03**	$0.04

The Company excluded 6.2 million options (June 30, 2011 – 6.3 million) and nil warrants (2011 – nil) and all convertible debentures (June 30, 2011 – all) for the year ended June 30, 2012 from the calculation of the diluted weighted average number of shares as they were anti-dilutive.

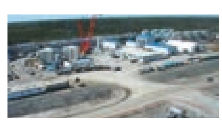
12. Contributed surplus:

	2012	2011
Balance, beginning of year	**$24,393**	$23,064
Options exercised	**(1,268)**	(1,481)
Stock-based compensation	**5,383**	2,810
Balance, end of year	**$28,508**	$24,393

13. 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 $771.3 million at June 30, 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 8). The Company has not paid or declared dividends since its reorganization of management and change in principal business on March 2, 2006.

14. 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. As at June 30, 2012 and June 30, 2011 all amounts are considered current and collectable.

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 June 30, 2012 were held with two banking institutions in Canada; $0.8 million with one and $19.8 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 June 30, 2012 the fair value is estimated to be an unrealized gain of $7.5 million (June 30, 2011 - $0.6 million gain). The following table summarizes the change in fair value of the Company's risk management contracts:

	2012	2011
Balance, beginning of year	**$570**	$273
Unrealized gain during the year	**6,914**	297
Balance, end of year	**$7,484**	$570

The Company has the following outstanding contracts as of June 30, 2012:

Type	Contract Term	Volume	Price
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:

	2012	**2011**
Unrealized gain	**$6,914**	$297
Realized gain (loss)	**2,313**	(11)
	$9,227	$286

As at June 30, 2012, had the forward price for WTI been US$1.00bbl higher or lower, the impact relating to the oil collar risk management contracts would have been a change in net income before income taxes of $0.5 million (June 30, 2011 – nil).

As at June 30, 2012, had the forward price for AECO been $0.10/GJ higher or lower, the impact relating to the natural gas risk management contracts would have been a change in net income before income taxes of nil (June 30, 2011 – $0.2 million).

As at June 30, 2012, had the forward price for $US dollar exchange rate been $0.01 higher or lower, the impact relating to the foreign exchange risk management contracts would have been a change in net income before income taxes of $0.2 million (June 30, 2011 – nil).

As at June 30, 2012, had the forward price for WTI been US$1.00bbl higher or lower, the impact relating to the differential swap risk management contracts would have been a change in net income before income taxes of $0.3 million (June 30, 2011 – nil).

(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 trade and other accounts receivable and trade and other accounts payable 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 14(b). Long-term debt is carried at amortized cost and the fair value, based on current market prices, is estimated to be $452.1 million, consisting of the term loan of $277.4 million and the convertible debentures of $174.7 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 8).

(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 and commodity price contracts that are settled in U.S. dollars. As at June 30, 2012, a $0.01 increase or decrease in the US to Canadian dollar exchange rate would have resulted in an increase or decrease in net income before income taxes of $2.5 million (June 30, 2011, $0.6 million). The Company's working capital as of June 30, 2012 denominated in U.S. dollars is $19.1 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:

	2012	2011
Unrealized foreign exchange loss (gain) on translation of:		
U.S. denominated second term loan facility	**$14,990**	$(7,993)
Foreign currency denominated cash balances	**(9,798)**	6,958
Unrealized foreign exchange loss (gain)	**$5,192**	$(1,035)

15. Related parties:

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Key management personnel include directors and executive officers of the Company. The compensation paid or payable for services is shown below:

	2012	2011
Salaries and benefits	**$3,061**	$1,858
Share based compensation	**2,360**	1,446
	$5,421	$3,304

Total salary and benefits paid for the year ended June 30, 2012 were $7.4 million (2011 – $4.9 million).

During 2012, the Company incurred legal costs of $0.8 million (2011 - $0.6 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, $0.1 million were included in accounts payable at June 30, 2012 (2011 – nil).

16. Commitments:

The Company is committed to annual lease payments, under the terms of leases for its head office space, other equipment and marketing agreements:

	June 30, 2012	June 30, 2011
2013	**$5,120**	$409
2014	**14,228**	409
2015	**14,043**	239
2016	**13,710**	-
2017	**12,588**	-
Thereafter	**13,957**	-
Total	**$73,646**	$1,057

At June 30, 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 $6.2 million in capital expenditure commitments to be made over the next year.

At June 30, 2012, as part of normal operations, the Company has entered into the following natural gas fixed purchase (AECO) price gas purchase contracts:

Contract Term	Volume	Price
January 1, 2012 to December 31, 2012	1,000 gj/day	$4.14
January 1, 2012 to December 31, 2012	1,000 gj/day	$4.00
January 1, 2012 to December 31, 2012	1,000 gj/day	$3.93
January 1, 2012 to December 31, 2012	500 gj/day	$3.86
July 1, 2012 to December 31, 2012	2,000 gj/day	$2.96
July 1, 2012 to December 31, 2012	1,000 gj/day	$2.75
January 1, 2013 to December 31, 2013	1,000 gj/day	$2.88
January 1, 2013 to December 31, 2013	1,000 gj/day	$2.95

17. Petroleum revenue:

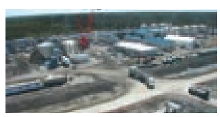
	2012	2011
Petroleum sales	**$84,651**	$93,727
Other income	**1,546**	484
Royalties	**(13,035)**	(15,274)
Saskatchewan resource surcharges	**(1,412)**	(1,588)
Petroleum revenue	**$71,750**	$77,349

18. Finance expense:

	2012	2011
Standby fees on revolving credit facility	**$597**	$326
Accretion of decommissioning liability	**49**	93
Total finance expense	**$646**	$419

19. Subsequent event:

On September 10, 2012 the Company entered into an agreement with a syndicate of underwriters to sell, on a bought deal basis, 51.7 million common shares of the Company at a price of $1.45 per common share for total gross proceeds of approximately $75.0 million. In addition, the Company has granted the underwriters an over-allotment option to acquire an additional 7.8 million common shares at a price of $1.45 per common share for additional gross proceeds of $11.0 million. The offering is scheduled to close on or about September 28, 2012.



20. Transition to IFRS:

These financial statements are the first prepared under International Financial Reporting Standards. The Company has prepared its opening statement of financial position at July 1, 2010 under these standards and has provided reconciliations to its previous results reported under Canadian GAAP. As well, the first year July 1, 2010 to June 30, 2011 of comparative historical results has been restated under IFRS along with reconciliations between Canadian GAAP and IFRS. This transition note explains the material adjustments made to the financial statements under Canadian GAAP to arrive at financial statements under IFRS.

In accordance with IFRS 1 "First Time Adoption of International Financial Reporting Standards" the Company applied the following mandatory and optional exemptions from full retrospective application of IFRS:

Mandatory:

- **Estimates** - Hindsight was not used to create or revise estimates and accordingly, the estimates made by the Company under previous GAAP are consistent with their application under IFRS.

- **Derecognition of financial assets and financial liabilities** - The Company applied the derecognition requirements in IAS 39 "Financial Instruments: Recognition and Measurement" prospectively for transactions occurring on or after July 1, 2010.

Optional:

- **Deemed cost of property, plant and equipment** - Full-cost oil and gas companies are allowed to measure oil and gas assets at the date of transition to IFRS at the amount determined under an entity's previous GAAP. This amount was pro-rated to assets within cash generating units using the recoverable reserve volumes at transition date.

- **Decommissioning liabilities** - The difference between the carrying values of the Company's decommissioning liabilities as measured under IAS 37 "Provisions, Contingent Liabilities and Contingent Assets" and their carrying values under Canadian GAAP has been recognized directly in retained earnings.

- **Business combinations** - This election has been taken to not apply IFRS 3 "Business Combinations" retrospectively to past business combinations. The Company has not restated business combinations that took place prior to the July 1, 2010 transition date.

- **Share-based payment transactions** - The election has been applied whereby the share-based payments under IFRS 2 "Share-based Payment" that had vested or settled prior to July 1, 2010 were not required to be retrospectively restated.

- **Borrowing costs** - IAS 23 "Borrowing Costs" has been applied to qualifying assets prospectively as of July 1, 2010.

- **Leases** - The exemption from the full retrospective application of IFRIC 4 "Determining whether an Arrangement contains a Lease" has been taken and arrangements were assessed using the facts at transition date rather than at the inception of the lease.

Reconciliation of consolidated statement of financial position and shareholders' equity at the date of transition to IFRS, July 1, 2010:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$63,505	$-	$63,505
Trade receivables		7,377	-	7,377
Prepaid expenses and deposits		232	-	232
Derivative assets		273	-	273
		71,387	-	71,387
Non-current assets:				
Exploration and evaluation assets	a	-	172,546	172,546
Property, plant and equipment	a	277,810	(172,546)	105,264
		$349,197	$-	$349,197
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$11,458	$-	$11,458
		11,458	-	11,458
Non-current liabilities:				
Decommissioning liability	c	6,449	3,736	10,185
Deferred income tax liability	d	39,770	(1,009)	38,761
		57,677	2,727	60,404
Shareholders' equity:				
Share capital	d	281,579	2,024	283,603
Contributed surplus	e	23,221	(157)	23,064
Deficit	c,d,e	(13,280)	(4,594)	(17,874)
		291,520	(2,727)	288,793
		$349,197	$-	$349,197

Reconciliation of consolidated statement of financial position and shareholders' equity at the end of the last reporting year under previous GAAP, June 30, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$322,927	$-	$322,927
Trade receivables		13,091	-	13,091
Prepaid expenses and deposits		1,157	-	1,157
Derivative assets		570	-	570
		337,745	-	337,745
Non-current assets:				
Exploration and evaluation assets	a	-	155,562	155,562
Property, plant and equipment	a,b,c	533,615	(148,035)	385,580
		$871,360	$7,527	$878,887
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$75,574	$-	$75,574
Current portion of long-term debt		2,652	-	2,652
		78,226		78,226
Non-current liabilities:				
Long-term debt	f	374,186	4,962	379,148
Decommissioning liability	c	10,043	12,084	22,127
Deferred income tax liability	d	38,201	7,996	46,197
		500,656	25,042	525,698
Shareholders' equity:				
Share capital	d	304,476	2,023	306,499
Equity component of convertible debentures	f	40,344	(15,060)	25,284
Contributed surplus	e	24,884	(491)	24,393
Retained earnings (deficit)	c,d,e	1,000	(3,987)	(2,987)
		370,704	(17,515)	353,189
		$871,360	$7,527	$878,887

Reconciliation of consolidated statement of comprehensive income for the year ended June 30, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenues and Other Income				
Petroleum revenue, net of royalties	d	$77,349	$-	$77,349
Gain on risk management contracts		286	-	286
		77,635	-	77,635
Expenses:				
Operating		15,680	-	15,680
Exploration and evaluation	a	-	456	456
General and administrative		9,527	-	9,527
Finance expense	c	713	(294)	419
Share based compensation	e	3,144	(334)	2,810
Depletion and depreciation	b,c	34,469	(4,049)	30,420
Gain on foreign exchange		(1,102)	-	(1,102)
Impairment	g	-	4,461	4,461
		62,431	240	62,671
Other:				
Gain on acquisition		3,585	-	3,585
		3,585	-	3,585
Income before income taxes		18,789	(240)	18,549
Deferred income tax expense	d	4,509	(847)	3,662
Net income and comprehensive income		$14,280	$607	$14,887

Notes:

(a) Exploration and 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 $155.6 million at June 30, 2011.

Exploration and evaluation expense relates to expired land and was $0.5 million at June 30, 2011.

(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. This amount was $4.0 million for the year ended June 30, 2011.

(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 3.08% 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 June 30, 2011 a risk-free rate of 3.11% was used which increased the decommissioning liability by a total of $12.1 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. At June 30, 2011 the decrease in accretion expense for the year was $0.3 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 – 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 being recorded at inception. This change also reduced the deferred income tax expense for the year 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. This adjustment was $0.7 million.

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 June 30, 2011 this amount was $0.3 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 $5.0 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 $15.1 million. The effective interest rate calculation was also adjusted to reflect the IFRS changes above.

(g) Impairment

Under IFRS impairment is done on a CGU basis rather than on a cost center basis. The oil and gas assets were impaired at June 30, 2011 for $4.5 million related to assets sold subsequent to June 30, 2011.

(h) 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.

Corporate Information

Officers

Byron Lutes, P.Eng.
President & Chief Executive Officer

Ron Clarke, P.Eng.
Chief Operating Officer

Howard Bolinger, C.A.
Chief Financial Officer

Glenn Miller
Vice President, Land & Regulatory Affairs

Jeff Barefoot, P.Eng., MBA
Vice President, Business Development

Chad Harris, M.Sc.
Vice President, Exploration

Wayne Beatty, P.Eng.
Vice President, Resource Development

Michael O'Krancy, P.Eng.
Vice President, Projects

Directors

David Antony, C.A.
Chairman of the Board

Jon P. Clark, M.S.Geol
Director

Ken Cullen, C.A.
Director

Ross D.S. Douglas, P. Eng., ICD.D
Director

Sid Dykstra, P.Eng., MBA
Director

Tibor Fekete, P.Eng.
Director

Byron Lutes, P.Eng.
Director, President & CEO

J. Ward Mallabone, L.LB
Director

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Legal Counsel

Davis LLP
Calgary, Alberta

Norton Rose
Calgary, Alberta

Stock Exchange Listing

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Transfer Agent

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McKay Facility
Sept 2012

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