BUILDING FROM THE GROUND UP

SOUTHERN PACIFIC
RESOURCE CORP.

ANNUAL REPORT 2011

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CORPORATE PROFILE

Southern Pacific Resource Corp. is engaged in the exploration, development and production of in-situ thermal heavy oil and bitumen production in the Athabasca oil sands of Alberta and in Senlac, Saskatchewan.

The Company trades on the TSX under the symbol "STP."

PRODUCING

BUILDING SOUTHERN PACIFIC INTO A SIGNIFICANT HEAVY OIL PRODUCER

HIGHLIGHTS FOR THE FISCAL YEAR ENDED JUNE 30, 2011:

- Averaged production of 4,915 bbl/d for the fourth quarter, an increase of 17% over the comparative period of the last fiscal year, and averaged 4,267 bbl/d for the year ended June 30, 2011;
- Increased funds from operations 45% to $51.9 million for the fiscal year 2011 compared to $35.8 million in the prior year;
- STP-McKay Phase 1 received full Energy Resources Conservation Board (“ERCB”) scheme approval on October 25, 2010, preceded by Government of Alberta Order in Council approval on October 14, 2010. Project construction commenced immediately following the project’s approval;
- Completed the final financing arrangements for construction of Phase 1 of the STP-McKay Thermal Project (“STP-McKay”), including $108.4 million of equity, $172.5 million of unsecured convertible debentures, a US$275.0 million second lien term loan facility and a $30.0 million first lien revolving facility, resulting in full funding for Phase 1 of STP-McKay;
- Increased proved (“1P”) reserves by 1,670% to 120.8 million barrels over the prior year as a result of further development of the STP-Senlac Thermal Project;
- Commenced construction of STP-McKay Phase 1; the Company continues to forecast project completion for calendar first quarter 2012, first steam for calendar second quarter 2012 and first oil in calendar third quarter 2012;
- Closed the acquisition of North Peace Energy on November 23, 2010 by the issuance of 14.1 million shares. Acquired assets include 135 sections of land in the Peace River oil sands area at a 100% working interest, a 1,000 bbl/day cyclic steam stimulation (CSS) pilot project at Red Earth, and potential for a 10,000 bbl/day thermal project;
- Announced STP McKay Phase 2 expansion plans for STP-McKay, which is expected to add an additional 24,000 bbl/d of bitumen capacity.

PUTTING OUR PLANS INTO ACTION

We have the assets. We have the people. And we have the production base. All that's left is to complete the construction of our STP-McKay Thermal Project, a major milestone in building Southern Pacific into a significant heavy oil producer from the ground up.

Southern Pacific has consistently been achieving milestones ahead of schedule and under budget as we put our plan into motion. By mid-2012, the steps we've taken to construct our 12,000 barrel per day (bbl/d) thermal in-situ project at STP-McKay, 45 km northwest of Fort McMurray, are expected to begin to pay dividends when the project comes on stream. Material production at STP-McKay is just around the corner. And that's only the beginning.

Much has happened since October 18, 2010 when we received approval from the Government of Alberta to proceed with the development of Phase 1 of STP-McKay. In early 2011 we closed the financings needed to fully fund the project. We then completed construction of a 29-km access road into the plant site to allow for all-season access in and out of the project. The earthworks have now also been completed for the Central Process Facility (CPF) and the first two SAGD well pads. Concurrently, we constructed a 14-km, 8-inch diameter natural gas pipeline to the CPF that will be used to transport natural gas to fire the electricity/steam cogenerators and steam generators. Source water wells and pipeline tie-ins have also been completed, and by the end of August, 2011, 100% of the major equipment purchase orders had been issued.

On August 31, 2011 we announced the successful completion of our steam-assisted gravity drainage ("SAGD") drilling program at STP-McKay, consisting of 12 SAGD well pairs that are expected to initially fill the plant design capacity. All 12 of the SAGD well pairs encountered high quality reservoir throughout and, most notably, the absence of lean zones and shale barriers in any of the well bores. This gives management confidence that the well pairs will perform as anticipated in the initial design. All horizontal sections were drilled to design length, with none of the well bores departing the edge of the exploitable reservoir. We completed the drilling operations with no re-drills or side tracks, nor with any difficulty running the slotted liners in the horizontal sections – a testament to the experienced drilling personnel on site and the sound technical design of the drilling program. The next step in preparing these wells for production will be to complete, equip and then tie them in to the central process facility located immediately south of the well pads. This will take place over the next several months, in time for the facility start-up.

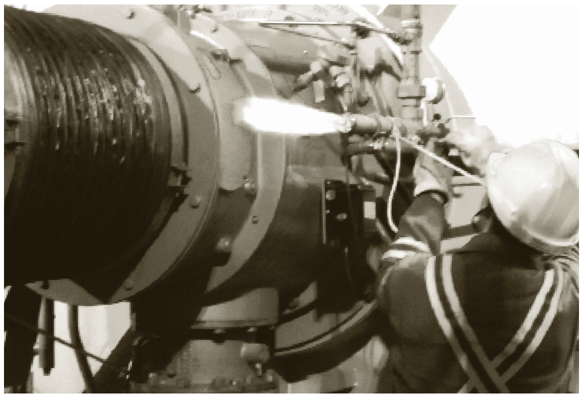
> "Although Phase 1 of STP-McKay is our focus right now, we are planning ahead to 2012 and beyond."

In order to share the progress and outcome of our efforts at STP-McKay, we installed cameras on the radio communications tower at the CPF in mid-2011. These cameras have been generating daily photographs that we've been posting on our website of the construction. We're now able to watch, along with our shareholders, as our plans come to life.

Although Phase 1 of STP-McKay is our focus right now, we are planning ahead to 2012 and beyond. From December 2010 to March 2011, we drilled a total of 38 exploration core holes, focused primarily on the eastern side of our existing STP-McKay project area, bringing the total core hole count to 88 inside the existing 10.5 square mile project area. Based on the positive drilling results, we announced plans to add 24,000 bbl/d of bitumen processing capacity to the STP-McKay project, increasing the total design capacity to 36,000 bbl/d. We estimate a total producing project life of about 25 years, based on the discovered recoverable bitumen to date, which the Company believes will provide an optimal life to maximize the project value. The STP-McKay Thermal Project – Phase 2 will be located on the east side of the McKay River, about 4.5 km from Phase 1. Phase 2 will be subdivided into two 12,000 bbl/d integrated stages. We believe this approach will allow us to make modifications to the final stage based on performance and operation of the previous stages. As well, it will allow for effective and efficient growth both from an operational and financial perspective.

In anticipation of Phase 2, Southern Pacific has been conducting baseline environmental work for the Phase 2 expansion since last summer. With the final size determined, the next steps in preparing the application are now underway, including air emission modeling and preparation of a scoping engineering study, followed by a Design Basis Memorandum (DBM) engineering study. We expect to submit an environmental impact assessment application for the entire 24,000 bbl/d expansion in the fourth quarter of calendar 2011. With that timeline, and allowing an 18-month approval process, construction of Phase 2A could commence in the third quarter of 2013, a little more than two and a half years after Phase 1. The timing of Phase 2B will be decided at a later date, but could reasonably be expected to commence within one to two years of the commencement of Phase 2A.

> "We have invested time and effort into building a strong technical team over the past year."



In addition to McKay and Senlac, we have long-term upside on a total of six oil sands blocks on 204,416 net acres of the Athabasca oil sands. In November 2010, we acquired North Peace Energy, adding 86,400 acres of oil sands leases and an existing thermal pilot project in the Peace River oil sands called STP-Red Earth.

While we pursue our plans in Alberta's oil sands, we have a base of cash flow from our producing SAGD project in southwest Saskatchewan. The STP-Senlac Thermal Project continues to fund our development work at STP-McKay. In fiscal 2011, Senlac continued to operate smoothly, with production averaging 4,267 bbl/d. Our plan is to keep Senlac's production between 4,000 and 5,000 bbl/d on an annual basis. The Company effectively brought on Phase H this past spring, which consists of two SAGD well pairs. We are currently drilling Phase J, which consists of three SAGD well pairs. The Phase J well pairs will remain on standby, ready to be placed on production once there is room in the plant to accommodate one or more of them.

Another huge achievement for the Company in fiscal 2011 was the continued positive reserve revisions we had at both Senlac and McKay. At Senlac, thanks to our drilling and performance, we were able to increase the remaining proved plus probable reserves by 2.9 MMbbl, despite having produced over 1.5 MMbbl of oil in the past year. Correspondingly, the net present value of STP-Senlac increased by 45% to $275 million (based on June 30, 2011 proven plus probable reserves before tax). In McKay we converted a significant amount of our reserves from probable to proven reserves. A total of 112 MMbbl are now classified as proven reserves. The amount of total proven plus probable reserves has increased to 168 MMbbl. This was a direct result of obtaining regulatory approval on Phase 1 and also further delineating the McKay project area with core holes over the past winter. We now have enough proven reserves to fill Phase 1 for more than 40 years and proven plus probable reserves for 50 years. This is one of the reasons we are proceeding with Phase 2 at McKay. The acceleration by expansion of the existing reserves and addition of contingent resources that will not currently fit within Phase 1 will significantly enhance the overall value of the STP-McKay project.

The final piece of our growth plan is our people. We have invested time and effort into building a strong technical team over the past year. We now sit at almost 80 (78 to be exact) full-time staff compared to a team of five three years ago. Over half of our staff is operations focused, highlighting the fact that Southern Pacific is on the verge of operating even more production. Our people are making a difference now, without delayed time frames to execute, like many of our peers. We embrace the challenge.

I would like to take this opportunity to welcome all new staff, and to thank everyone who continues to do a superb job. I would also like to thank our Board of Directors for their tireless efforts. Finally, I would like to thank our shareholders for their support and confidence as we put our plans into action.

On behalf of the management team,

Byron Lutes, President & CEO
Southern Pacific Resource Corp.

September 2011

PLANNING

KEEPING PROJECTS ON TRACK AND ON BUDGET

Southern Pacific remains focused on the construction and operation of Phase 1 of the STP-McKay Thermal Project. Construction has been underway since the project received regulatory approval in the fall of 2010.

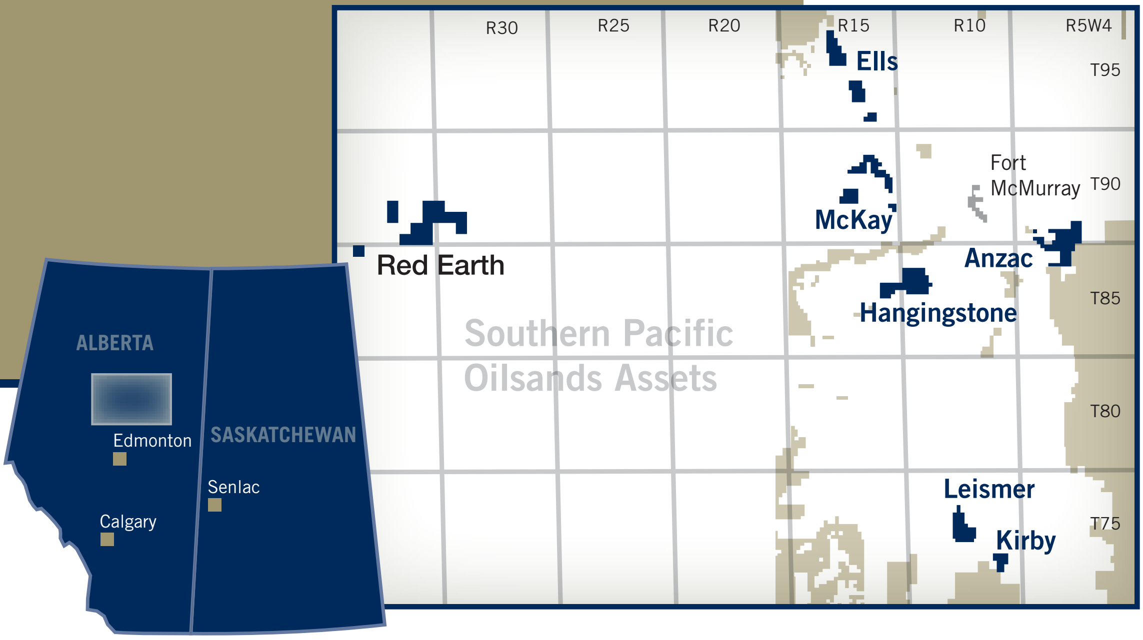
Our team of employees is working hard to see our project through to completion.

A recent milestone at STP-McKay was the successful drilling of 12 SAGD well pairs, which achieved excellent results. At the central process facility site various structures are beginning to elevate above ground level as the earthworks, including site civil preparation and pile driving, near completion. The main construction operations underway at the plant site include continued pile driving, pouring cement foundations, erecting storage tanks and constructing the 85-person operations camp. More than 80% of the modules, skids and equipment packages have been released for shop fabrication. Modules have started to arrive on site and are scheduled to continue to arrive over the coming months. First steam is expected in calendar Q2-2012 and first oil is expected in Q3-2012. The Company is fully funded to complete the construction, commissioning, start-up and into operations at STP-McKay Phase 1.

In conjunction with the construction of STP-McKay Phase 1, the Company is preparing an application for a 24,000 bbl/d thermal project at STP-McKay Phase 2. STP-McKay Phase 2 will be focused on recovering bitumen through in-situ SAGD recovery methods on the east side of the McKay River. The STP-McKay Phase 2 plant design, construction and operation will mimic those of STP-McKay Phase 1 in an effort to increase area operational synergies. The project's application is expected to be completed and submitted to the regulatory bodies in Q4-2011.

Southern Pacific continues to maintain oil production levels between 4,000 and 5,000 bbl/d at Senlac. The Company drilled, completed and equipped two SAGD pairs at Phase H. The wells were put on production on April 7, 2011 and have added 2,560 bbl/d of production. The Company has continued development at Senlac and plans to drill, complete and equip three SAGD well pairs at Phase J in the fall of 2011.

The STP-Red Earth Thermal Project also commenced operations in the fourth quarter. This 1,000 bbl/d pilot project was re-activated this past spring after the acquisition of North Peace. The Company is testing three separate well bores, using cyclic steam stimulation ("CSS") as the technique for recovery. Each well bore has a unique configuration and the Company intends to continue testing the wells through the fall of 2011. Following this initial testing, the data will be analyzed and plans will be made to determine the next steps in establishing an overall development plan for this project and future expansion plans.



PRINCIPAL PROPERTIES

McKay, Alberta

> "At the central process facility site, various structures are beginning to elevate above ground level."

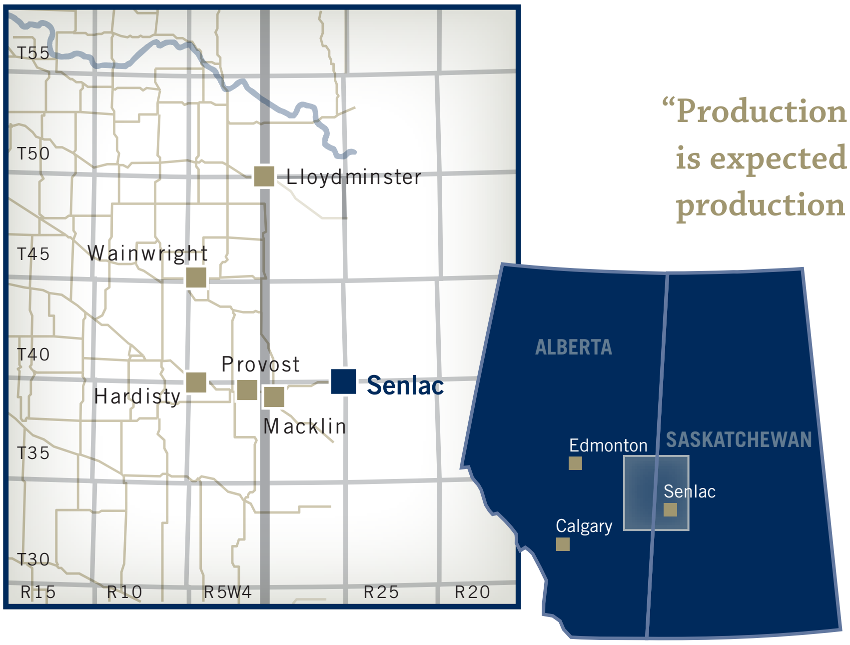
Phase 1 Construction

The STP-McKay Thermal Project is a 100% owned and operated SAGD project designed to process 12,000 bbl/d of bitumen and generate 33,600 bbl/d of steam. Southern Pacific has drilled a total of 12 SAGD well pairs that are expected to fill the plant design capacity. The wells were drilled from two pads. The first pad has effective horizontal well lengths averaging 800 metres and the second pad averages 1,100 m. In total, Southern Pacific has completed 23.1 kilometres of horizontal drilling through the bitumen bearing McMurray formation.

In addition to the SAGD production pairs, Southern Pacific drilled a horizontal observation well into the Wabiskaw formation with 800 m of open-hole liner. The Company drilled this well above a SAGD well pair on Pad 101 to evaluate pressure and temperature in the Wabiskaw formation as an indicator of steam/production performance in the underlying McMurray formation. This observation well will also allow Southern Pacific to assess the viability of recovering the significant bitumen deposit from within the Wabiskaw formation using CSS and heat conduction from the underlying SAGD process.

As of August 31, 2011, the construction costs of the STP-McKay Thermal Project are expected to be below the original budget estimate of $450 million. With approximately $355 million (81%) of capital committed and $237 million (54%) actually incurred to date, the Company projects that the total project capital cost will fall between $415 to $440 million. The cost reduction is primarily due to a successful civil construction program which is nearing completion. This estimate includes about $15 million of unbudgeted scope additions that are expected to enhance the reliability and reduce operating costs of the facility. These enhancements include additional diluted bitumen ("dilbit") storage, a concentrator to increase produced water recycle, the purchase (versus renting) of rig mats for future SAGD drilling, a second free water knockout system, additional truck loading capacity and increasing the cogeneration efficiency.

The main construction operations currently underway at the plant site include continued pile driving, pouring cement foundations, erecting storage tanks and constructing the operations camp. Over 70% of the modules, skids and equipment packages have been released for shop fabrication and modules have started to arrive on site.



> "Production from Phase J is expected to be available for production in December 2011."

Southern Pacific expects first steam to the SAGD well pairs will occur on schedule in the second quarter of calendar 2012. The Company remains well capitalized and expects no financial concerns completing the project, starting it up, and adding this production to its existing base.

Senlac

During fiscal 2011, production at the STP-Senlac Thermal Project averaged 4,267 bbl/d. The Company drilled, completed and equipped two SAGD well pairs at Phase H and began producing oil from Phase H on April 7, 2011. This resulted in total average daily production for the quarter ended June 30, 2011 4,915 bbl/d. The Company plans to follow up with three SAGD well pairs at Phase J in the fall of 2011. Production from Phase J is expected to be available for December 2011.

Drilling activities at Senlac resulted in positive reserve revisions in fiscal 2011. Proven plus probable reserves increased by 2.9 MMbbl. This resulted in a boost to the net present value of STP-Senlac by 45% to $275 million. This estimate is based on proven plus probable reserves before tax as of June 30, 2011.

Southern Pacific expects to maintain Senlac production at high levels for the next 10 to 15 years with a best-in-class steam-oil ratio of 2.0 to 2.2. Senlac is expected to generate net operating income of approximately $65 million per year.

Red Earth

On November 23, 2010 Southern Pacific closed the acquisition of North Peace Energy.

Acquisition highlights:

- 135 sections of 100% working interest oil sands leases in the Peace River oils sands area;
- 2.1 billion barrels of discovered bitumen resource based on 27 delineation wells and over 360 legacy well bores;
- 105 million barrels of 'Best Estimate' contingent resource;
- 1,000 bbl/d Red Earth CSS Pilot Plant; and
- Potential plans for at least a 10,000 bbl/d thermal project on the current contingent resources.

Southern Pacific commenced pilot work at Red Earth in June 2011, which will utilize the existing 1,000 bbl/d thermal plant and further test the Blue Sky formation for CSS production potential. Pilot work will continue through the fall of 2011.

Slant rig drilling SAGD wellpairs at Southern Pacific's STP-McKay Thermal Project, 45 km northwest of Fort McMurray, Alberta.

SOUTHERN PACIFIC'S OIL SANDS PROSPECT AREAS

Outside of McKay, Southern Pacific also holds 242 sections of oil sands leases in the Athabasca oil sands region of Alberta and an additional 135 sections of oil sands leases at Red Earth in the Peace River oil sands area of Alberta. The properties are split into six blocks: Anzac, Hangingstone, Leismer, Kirby, Ells and Red Earth. Anzac (89% average working interest) is 75 sections (42,496 net acres), Hangingstone (80% working interest) is 66 sections (33,792 net acres), Leismer (80% working interest) is 36 sections (18,432 net acres), Kirby (80% working interest) is 15 sections (7,680 net acres), Ells (49% average working interest) is 50 sections (15,616 net acres) and Red Earth (100% working interest) is 135 sections (86,400 net acres) of land.

Significant tenure remains on the leases, ranging from 9 to 11 years. Over the past three years, the Company has shot, acquired and processed 608 km of 2D seismic and 20 square km of 3D seismic and drilled 96 exploratory core holes on these lands. Southern Pacific intends to continue exploration on these land blocks as part of its annual capital program, with the purpose of identifying and planning future thermal project areas and allowing for continued growth beyond the STP-McKay, STP-Senlac and STP-Red Earth Thermal Projects.

OIL SANDS AND HEAVY OIL RESERVES

In a report prepared by GLJ Petroleum Consultants ("GLJ") dated June 30, 2011, Southern Pacific's total proved "1P" reserves increased 1,670% year over year to 120.8 million barrels of oil equivalent ("MMboe"). This increase is primarily due to regulatory approval of the STP-McKay project whereby 114.0 MMboe of reserves were graduated from total proved plus probable ("2P") reserves to 1P reserves. Total proved plus probable reserves increased by 1% to 181.0 MMboe primarily due to continued successful delineation of the STP-McKay Thermal Project. The Company's best estimate ("P50") contingent resources also increased by 36% to 665.5 MMboe, primarily due to exploration program success and the acquisition of North Peace.

GLJ's year-end reserves evaluation also includes evaluations of the unconventional bitumen contingent resources on the Company's 192,640 gross acres (155,776 net) of oil sands leases. The contingent resources evaluation excluded the 86,400 net acres of land acquired in the North Peace acquisition. An update to these lands is expected to be completed in fiscal 2012.

The following table summarizes Southern Pacific's working interest reserves effective June 30, 2011.

	Working Interest Recoverable (MMboe)	Before Tax Net Present Value (CDN $ million) 8%	10%	12%
Reserves				
Total Proved (1P)	121	$ 893	$ 726	$ 602
Proved + Probable Reserves (2P)	181	1,383	1,109	915
Proved + Probable + Possible (3P)	209	$ 1,736	$ 1,390	$ 1,147

The evaluation by GLJ is effective June 30, 2011, which is the Company's fiscal year end. The report was prepared in accordance with National Instrument 51-101 using the assumptions and methodology outlined in the Canadian Oil and Gas Evaluation Handbook. The GLJ Report is incorporated into Southern Pacific's Annual Information Form.

CONTINGENT RESOURCES ESTIMATES

GLJ also completed evaluations of the Corporation's year-end unconventional bitumen contingent resources located on the Company's oil sands leases in the Athabasca region of northern Alberta.

The following table summarized the Company's working interest contingent resources effective June 30, 2011 for the leases in the Athabasca region.

	Working Interest Recoverable (MMboe)	Net Present Value (Before Tax - WI) (CDN $ million) 8%	10%	12%
Contingent Resources				
Low Estimate (P90) Contingent Resource	180	$ 965	$ 652	$ 416
Best Estimate (P50) Contingent Resource	561	2,573	1,688	1,055
High Estimate (P10) Contingent Resource	1,169	$ 6,215	$ 4,218	$ 2,806

Sproule Unconventional Limited conducted an evaluation of contingent resources regarding the Corporation's oil sands leases in Red Earth in the Peace River region. This report is titled "North Peace Energy Corporation Oil Sands Resources Evaluation in the Red Earth Area of Alberta (as of December 31, 2009)" and is dated February 4, 2010.

The following table summarized the Company's working interest contingent resources effective December 31, 2009 for the leases in the Peace River Region.

	Working Interest Recoverable (MMboe)	Net Present Value (Before Tax - WI) (CDN $ million) 8%	10%	12%
Contingent Resources at December 31, 2009				
Low Estimate (P90) Contingent Resource	64	$ (266)	$ (263)	$ (256)
Best Estimate (P50) Contingent Resource	105	170	81	36
High Estimate (P10) Contingent Resource	146	$ 495	$ 327	$ 239

Note: Reserves and contingent resources involve different risks associated with achieving commerciality. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Future net revenues associated with reserves and resources do not necessarily represent fair market value.

PRODUCTION VOLUME BY FIELD

The following table discloses for each important field, and in total, the Company's production volumes for the financial year ended June 30, 2010 for each product type.

Field	Heavy Oil (bbl/d)	Oil and NGLs (bbl/d)	Natural Gas (Mcf/d)	Boe (boe/d)	%
Senlac	4,205	–	–	4,205	98.5%
Other	–	25	221	62	1.5%
Total	4,205	25	221	4,267	100%

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of undeveloped properties in which Southern Pacific has an interest and also the number of net acres for which Southern Pacific has rights to explore, develop or exploit will, absent further action, expire within one year.

Area	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Alberta	276,640	239,456	–
Saskatchewan	160	160	–
Total	276,800	239,616	–

DEFINITIONS

- Discovered Bitumen Resource, or Discovered Bitumen Initially-In-Place, is the quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Bitumen Initially-In-Place includes production, reserves, and contingent resources; the remainder is unrecoverable.
- "Contingent Resources" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.
- "High (P10)" means an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
- "Best (P50)" means the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- "Low (P90)" means a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- "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.

BRINGING IN THE BOILER

Southern Pacific had planned to replace a boiler at Senlac this year and managed to find exactly the right boiler on a classified ad website. The boiler had never been used and required only a few parts. The purchase price was approximately $90,000, resulting in a total savings of more than $700,000 including installation.

DELIVERING THE PLAN IS PAYING OFF

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

Three and Twelve Months Ended June 30, 2011

OVERVIEW

Southern Pacific Resource Corp. ("Southern Pacific" or the "Company") is engaged in the exploration and development of in-situ oil sands in the Athabasca and Peace River 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."

The following Management's Discussion and Analysis ("MD&A") is a review of the operations, current financial position and outlook for Southern Pacific and is prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended June 30, 2011. This MD&A is dated September 21, 2011. The financial statements and financial data contained in this MD&A have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") in Canadian currency.

The terms "2011" and "2010" are used throughout this document and refer to the fiscal years ended June 30, 2011 and 2010, respectively. References to "fourth quarter 2011" in this document refer to the three month financial period ended June 30, 2011. References to "fourth quarter 2010" in this document refer to the comparative three month financial period ended June 30, 2010.

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.

OVERALL PERFORMANCE

Highlights for fiscal 2011 include the following:

- Averaged overall production of 4,267 bbl/d, an increase of 44% over average production of 2,956 bbl/d in fiscal 2010;
- Increased funds from operations 45% to $51.9 million compared to $35.8 million in the prior year;
- Received Order In Council approval from the Government of Alberta for STP-McKay Phase 1 on October 15, 2010, and subsequently received the Energy Resources Conservation Board ("ERCB") scheme approval on October 25, 2010;
- Increased proved ("1P") reserves by 1,670% to 120.8 million barrels over the prior year due to regulatory approval of the STP-McKay Thermal Project ("STP-McKay") and 2011 winter core hole program;
- Completed the final financing arrangements for construction of STP-McKay Phase 1, including $172.5 million of unsecured convertible debentures, a US$275.0 million second lien term loan facility and a $30.0 million first lien revolving facility, resulting in full funding for STP-McKay Phase 1;
- Commenced construction of STP-McKay Phase 1. The Company continues to forecast project completion for calendar first quarter 2012, first steam for calendar second quarter 2012 and first oil in calendar third quarter 2012;
- Closed the acquisition of North Peace Energy on November 23, 2010. Acquired assets include 135 sections of land in the Peace River oil sands area at a 100% working interest, a 1,000 bbl/day cyclic steam stimulation (CSS) pilot project at Red Earth, and potential for a 10,000 bbl/day thermal project; and
- Announced and began preparing application for STP McKay Phase 2, which is expected to add 24,000 bbl/d of bitumen capacity.

OUTLOOK

Southern Pacific remains focused on the construction and operation of Phase 1 of STP-McKay. The 12,000 bbl/d steam-assisted gravity drainage (SAGD) project was approved in the fall of 2010, and construction has been underway since. The Company continues to expect the project to be completed within its budgeted time frame and now expects the total cost to come in below the original $450 million budget. The revised final project cost estimate is between $415 and $440 million, including the addition of $15 million of scope changes that are expected to enhance the reliability of the plant and reduce operating costs. This estimate is $10 to $35 million below the original budget.

The project milestones have been most recently marked by the successful drilling of 12 SAGD well pairs, which were drilled with excellent results. All 12 of the SAGD well pairs encountered high quality reservoir throughout and, most notably, the absence of lean zones and shale barriers in any of the well bores. This gives management confidence that the well pairs will perform as expected in the initial design. All horizontal sections were drilled to design length, with none of the well bores departing the exploitable reservoir. Southern Pacific completed the drilling operations with no re-drills or side tracks, nor with any difficulty running the slotted liners in the horizontal sections.

At the central process facility site, various structures are beginning to elevate above ground level, as the earthworks including site civil preparation and pile driving near completion. The Company recognized significant savings in the plant and pad site civil works, thanks in part to efficient construction management and contractors, and also because competent clay material was found locally from which to construct the sites.

The main construction operations underway at the plant site include continued pile driving, pouring cement foundations, erecting storage tanks and constructing the 85 person operations camp. Over 80% of the modules, skids and equipment packages have been released for shop fabrication. Modules have started to arrive on site and are scheduled to continue to arrive over the coming months.

From a timing perspective, Southern Pacific expects first steam to the SAGD well pairs will occur on schedule in the second quarter of calendar 2012. The Company remains fully funded to complete, start up and add production volumes from the STP-McKay project.

At the STP-Senlac Thermal Project ("STP-Senlac") located in southwestern Saskatchewan near Unity, Southern Pacific remains committed to its development plan, which includes maintaining production levels on an annual basis between 4,000 and 5,000 bbl/d. Over the past quarter, the property achieved an average production rate of 4,829 bbl/d; this is credited to the recent addition of Phase H. Phase H consists of two SAGD well pairs which were placed on production in April 2011.

As part of its development strategy, Southern Pacific is now drilling and preparing Phase J for production. Phase J consists of three SAGD well pairs; these well pairs may not all be needed until later in the fiscal year and they will be layered into the facility as capacity permits.

A two week scheduled maintenance turnaround is currently underway at STP-Senlac. There has not been the need for a maintenance turnaround at the facility for over two years, a testament to the talented operations staff operating the facility.

The STP-Red Earth Thermal Project has also commenced operations in the fourth quarter. This 1,000 bbl/d pilot project was re-activated this past spring after the acquisition of North Peace. The Company is testing three separate well bores, using cyclic steam stimulation ("CSS") as the technique for recovery. Each well bore has a unique configuration and the Company intends to continue testing the wells through the fall of 2011. Following this initial testing, Southern Pacific will analyze the data and determine the next steps in establishing an overall development plan for this project and future expansion plans.

RESULTS OF OPERATIONS

Production

	Three Months Ended June 30,			Twelve Months Ended June 30,		
	2011	**2010**	**Change**	**2011**	**2010**	**Change**
Heavy oil (bbl/day)	**4,829**	4,104	18%	**4,205**	2,825	49%
Oil and NGLs (bbl/day)	**39**	25	56%	**25**	30	(17%)
Natural gas (mcf/day)	**284**	373	(24%)	**221**	607	(64%)
Total (boe/day)	**4,915**	4,191	17%	**4,267**	2,956	44%

Production for the quarter ended June 30, 2011 averaged 4,915 barrels of oil equivalent per day (boe/day), an increase of 17% over the same period in 2010. The increase is largely attributable to the addition of two Phase H SAGD well pairs that were put on production in April 2011. The increased production for the year ended June 30, 2011 to 4,267 boe/day over the same period in 2010 was the result of the acquisition of the Senlac facility on November 3, 2009 (only 239 days of Senlac production are included in the 2,956 boe/day for the year ended June 30, 2010). The oil, natural gas liquids (NGLs) and natural gas production decreases for the year ended June 30, 2011 were a result of the sale of non-core conventional assets in the third quarter of fiscal 2010.

Product Prices

	Three Months Ended June 30,			Twelve Months Ended June 30,		
	2011	**2010**	**Change**	**2011**	**2010**	**Change**
Oil and NGLs ($ per bbl)	**$ 70.27**	$ 71.61	(2%)	**$ 70.54**	$ 69.21	2%
Natural gas ($ per mcf)	**3.69**	3.16	17%	**3.71**	3.97	(7%)
Combined average ($ per boe)	**$ 68.68**	$ 54.21	27%	**$ 60.17**	$ 57.50	5%

The heavy oil price received by Southern Pacific was $69.05 per bbl for the quarter ended June 30, 2011, 26% higher than the same quarter in 2010. For the year ended June 30, 2011, the heavy oil price increased by 3% over the prior year. The increase in the heavy oil price for the quarter and the year ended is largely attributable to the increase in the WTI crude oil price partially offset by increased heavy oil differentials.

Oil and NGLs prices received were $70.27 per bbl for the quarter ended June 30, 2011, representing a 2% decrease from the same quarter in 2010 due to prior period adjustments. Oil and NGLs prices received were $70.54 for the year ended June 30, 2011, representing a 2% increase over the prior year due to the increase in WTI.

Natural gas prices for the quarter ended June 30, 2011 increased from the same quarter in 2010 by 17%. For the year ended June 30, 2011, natural gas prices decreased by 7% over the same period in 2010.

Operating Netbacks

	Three Months Ended June 30,			Twelve Months Ended June 30,		
	2011	**2010**	**Change**	**2011**	**2010**	**Change**
Combined average ($ per boe)	**$ 68.68**	$ 54.21	27%	**$ 60.17**	$ 57.50	5%
Royalties ($ per boe)	**(11.56)**	(8.18)	41%	**(9.81)**	(8.94)	10%
Operating costs ($ per boe)	**(8.91)**	(9.67)	(8%)	**(10.07)**	(9.88)	2%
Operating netback ($ per boe)	**$ 48.21**	$ 36.36	32%	**$ 40.29**	$ 38.68	4%

Operating netbacks for the quarter and year ended June 30, 2011 were both higher than the same periods in the prior year. This increase is due to the higher average combined product price received offset by higher royalties (discussed in further detail below).

Oil and Gas Revenue

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands)	**2011**	**2010**	**Change**	**2011**	**2010**	**Change**
Heavy oil	**$ 30,379**	$ 20,404	49%	**$ 92,773**	$ 60,401	54%
Oil and NGLs	**247**	161	53%	**654**	762	(14%)
Natural gas	**95**	107	(11%)	**300**	880	(66%)
Total oil and gas revenue	**$ 30,721**	$ 20,673	48%	**$ 93,727**	$ 62,043	51%

Revenue from oil and natural gas sales for the quarter ended June 30, 2011 was $30.7 million, compared to $20.7 million in the same quarter of 2010. The heavy oil revenue increase was a result of higher production and realized heavy oil pricing. The oil and NGLs increased revenues were a result of higher production. Natural gas revenue decreases were a result of dispositions of non-core conventional assets in the prior year.

Revenue from oil and natural gas sales for the year ended June 30, 2011 was $93.7 million, compared to $62.0 million for the same period in 2010. The significant revenue increase was the result of increased production over the prior year and increased realized heavy oil prices in 2011. The oil, NGLs and natural gas revenue decreases were a result of dispositions of non-core conventional assets in the prior year.

Risk Management Contracts

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands)	**2011**	**2010**	**Change**	**2011**	**2010**	**Change**
Unrealized gain	**$ 5,971**	$ 1,405	325%	**$ 298**	$ 273	9%
Realized (loss)	**(174)**	(74)	135%	**(12)**	(75)	(84%)
Risk management contracts	**$ 5,797**	$ 1,331	336%	**$ 286**	$ 198	44%

For the three and twelve months ended June 30, 2011, Southern Pacific recorded an unrealized gain on risk management contracts of approximately $6.0 million and $0.3 million, respectively, compared to an unrealized gain of $1.4 million and $0.3 million for the same periods in 2010. For the three and twelve months ended June 30, 2011, the Company recorded a realized loss on risk management contracts of approximately $0.2 million and $0.1 million, respectively, compared to a realized loss of $0.1 million for the three and twelve months ending June 30, 2010. The risk management contracts represent the change in fair value of the commodity contracts held by Southern Pacific. The intent of these risk management contracts is to protect the downside risk to the Company's cash flow. The contracts are listed in detail in the Commitments section of this MD&A.

Royalties

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands except for % and per boe)	**2011**	**2010**	**Change**	**2011**	**2010**	**Change**
Royalties	**$ 5,169**	$ 3,121	66%	**$ 15,274**	$ 9,642	58%
% of oil and gas revenue	**16.8%**	15.1%	11%	**16.3%**	15.5%	5%
Per boe	**$ 11.56**	$ 8.18	41%	**$ 9.81**	$ 8.94	10%

Royalties for the quarter ended June 30, 2011 were $5.2 million, compared to $3.1 million for the same quarter in 2010. The increase is primarily due to higher heavy oil production and higher prices received at Senlac. Royalties represented 16.8% of total petroleum and natural gas revenue for the quarter ended June 30, 2011, compared to 15.1% in the same quarter of 2010. On a per boe basis, royalties were $11.56 for the quarter ended June 30, 2011 compared to $8.18 for the quarter ended June 30, 2010. On a percentage basis, royalty rates for the quarter have increased due to decreased capital spending and operating costs relative to the prior quarter. The royalty rates at Senlac are on a sliding scale dependent upon the level of capital and operating spending. 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.

Royalties for the year ended June 30, 2011 were $15.3 million, compared to $9.6 million for the year in 2010. As a percentage of revenue the royalty rate increased to 16.3% versus 15.5% in the prior year, which is consistent with the reduced capital spending.

Operating Costs

($ thousands except for per boe)	Three Months Ended June 30, 2011	2010	Change	Twelve Months Ended June 30, 2011	2010	Change
Natural gas costs	**$ 1,818**	$ 1,617	12%	**$ 6,509**	$ 4,814	35%
Other operating costs	**2,166**	2,070	5%	**9,171**	5,842	57%
Operating costs	**3,984**	3,687	8%	**15,680**	10,656	47%
Operating costs per boe	**$ 8.91**	$ 9.67	(8%)	**$ 10.07**	$ 9.88	2%

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 this risk by selectively hedging a portion of its natural gas purchases throughout the year.

In total, operating costs were $4.0 million for the quarter ended June 30, 2011, compared to $3.7 million for the same quarter of 2010. On a per boe basis, operating costs decreased to $8.91 for the three months ended June 30, 2011 from $9.67 for the same period in 2010 due to lower workover costs.

Operating costs were $15.7 million for the year ended June 30, 2011, compared to $10.7 million for the same period of 2010. On a per boe basis, operating costs were $10.07 for the year ended in 2011 compared to $9.88 for the year ended in 2010. The slight increase over the year was due to increased workover costs at Senlac offset by slightly lower natural gas prices in 2011.

General and Administrative Expenses

($ thousands except for per boe)	Three Months Ended June 30, 2011	2010	Change	Twelve Months Ended June 30, 2011	2010	Change
General and administrative expenses	**$ 3,187**	$ 1,519	110%	**$ 9,527**	$ 4,064	134%
Per boe	**$ 7.12**	$ 3.98	79%	**$ 6.12**	$ 3.77	62%

General and administrative expenses for the three and twelve months ended June 30, 2011 of $3.2 million and $9.5 million, respectively, are higher compared to $1.5 million and $4.1 million for the same periods of 2010. The increase is due to additional personnel hired and administration costs required for STP-McKay Phase 1 that is under construction.

For the three months and year ended June 30, 2011, $0.4 million and $0.6 million, respectively, of general and administrative expenses were capitalized. These general and administrative expenses represent costs directly attributable to STP-McKay Phase 1.

Interest and Financing

($ thousands except for per boe)	Three Months Ended June 30, 2011	2010	Change	Twelve Months Ended June 30, 2011	2010	Change
Interest and financing	**$ 143**	$ 83	72%	**$ 326**	$ 947	(66%)
Per boe	**$ 0.32**	$ 0.22	47%	**$ 0.21**	$ 0.88	(76%)

Interest and financing expenses for the three months ended June 30, 2011 were higher than the previous period due to the increase in standby fees related to the new credit facility. Interest and financing expenses for the year ended June 30, 2011 were lower than the previous year as a result of the Company not having any amounts drawn on its credit facility for fiscal 2011. Interest and financing expenses consist of bank loan arrangement fees and standby fees. Interest costs of $22.9 million related to the completed financing are being capitalized as part of STP-McKay Phase 1.

Depletion, Depreciation and Accretion

($ thousands except for per boe)	Three Months Ended June 30, 2011	2010	Change	Twelve Months Ended June 30, 2011	2010	Change
Depletion and depreciation	**$ 8,025**	$ 9,967	(19%)	**$ 34,469**	$ 28,176	22%
Accretion	**112**	114	(2%)	**387**	422	(8%)
Total	**8,137**	10,081	(19%)	**34,856**	28,598	22%
Per boe	**$ 18.19**	$ 26.43	(31%)	**$ 22.38**	$ 26.50	(16%)

Depletion, depreciation and accretion expense ("DD&A") of $8.0 million for the quarter decreased over the prior period in 2010 by 19% on an absolute basis and 31% on a per boe basis. The decrease was the result of reserve additions at Senlac. For the year ended June 30, 2011, the DD&A at $22.38 per boe was also lower than the prior period due to the reserve additions at Senlac. However, on an absolute basis, the DD&A increased from the prior period primarily due to higher production levels at Senlac.

The depletion on petroleum and natural gas properties is booked on a quarterly basis. For the quarter ended June 30, 2011, $442.0 million in oil sands properties and unproven costs were excluded from the depletion calculation, and $68.6 million of future development costs were added.

Southern Pacific's asset retirement obligation ("ARO") represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The ARO may be increased over time based on new obligations (wells drilled), constructing facilities, acquiring operations, or adjusting future estimates related to timing and dollar amounts. Similarly, the ARO obligation can be reduced as actual abandonment costs are undertaken reducing future obligations. The accretion charge of $0.1 million for the quarter ended June 30, 2011 and $0.4 million for the year ended June 30, 2011 represents the change in the estimated time value of the ARO. Currently the discounted ARO liability is estimated at $10.0 million and will be accreted up to the estimated undiscounted ARO liability of $56.1 million over the remaining economic life of the Company's oil sands assets and conventional crude oil and natural gas properties.

Foreign Exchange

For the three and twelve months ended June 30, 2011 the foreign exchange gain was $0.4 million and $1.1 million, respectively. The foreign exchange gain is the result of Southern Pacific completing a U.S. term loan facility during the year and the resulting strengthening of the Canadian dollar compared to the U.S. dollar. The U.S. debt and resulting cash received is 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 re-valued into Canadian dollars is recorded as the foreign exchange gain or loss.

Stock-Based Compensation

($ thousands except for per boe)	Three Months Ended June 30, 2011	2010	Change	Twelve Months Ended June 30, 2011	2010	Change
Stock-based compensation	**$ 801**	$ 820	(2%)	**$ 3,144**	$ 3,203	(2%)
Per boe	**$ 1.79**	$ 2.15	(17%)	**$ 2.02**	$ 2.97	(32%)

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 ended June 30, 2011 stock-based compensation was $0.8 million, compared to $0.8 million for the same period in 2010. During the year ended June 30, 2011, stock-based compensation was $3.1 million, comparable to $3.2 million booked for the same period in 2010.

Income Taxes

Saskatchewan resources surcharges for the three and twelve months ended June 30, 2011 were $0.5 million and $1.6 million, compared to $0.4 million and $0.9 million for the three and twelve months in 2010. The Saskatchewan resource surcharges are calculated on a percentage of the Company's resource sales in the province of Saskatchewan.

Southern Pacific recorded a $4.7 million and $4.5 million future tax expense for the quarter and twelve months ended June 30, 2011, respectively. This is compared to a $3.7 million expense and $4.0 million future tax recovery for the comparative quarter and twelve months ended June 30, 2010.

The Company estimates it has approximately $456.3 million in tax pools before the deferred partnership income allocation as at June 30, 2011. Deferred partnership income is estimated to be $54.8 million, which would reduce the tax pools to $401.5 million. Both balances include $143.7 million in non-capital tax losses which expire over time from 2014 to 2030. Southern Pacific is not currently taxable and does not expect to pay taxes in fiscal 2012 except for the Saskatchewan Resource Surcharges discussed above.

Net Income (Loss)

Southern Pacific recorded a net income of $10.7 million, or $0.03 per share, for the quarter ended June 30, 2011, compared to a net loss of $1.3 million, or $(0.00) per share, in the same quarter of the prior year.

For the year ended June 30, 2011, the Company recorded net income of $14.3 million, or $0.04 per share, compared to $8.2 million, or $0.04 per share, in the prior year.

FUNDS FROM OPERATIONS

	Three Months Ended June 30,			Twelve Months Ended June 30,		
($ thousands except per boe and per share)	**2011**	**2010**	**Change**	**2011**	**2010**	**Change**
Funds from operations	**$ 17,942**	$ 11,837	52%	**$ 51,872**	$ 35,773	45%
Funds from operations per boe	**40.11**	31.04	29%	**33.31**	33.16	0%
Funds from operations basic and diluted per share	**$ 0.05**	$ 0.04	25%	**$ 0.16**	$ 0.18	(11%)

Funds from operations were $17.9 million for the quarter ended June 30, 2011, which is higher than the $11.8 million in the quarter ended June 30, 2010. On a per share basis, this equaled $0.05 versus $0.04, respectively. The increase is attributable to higher production and prices.

Funds from operations were $51.9 million for the year ended June 30, 2011, compared to $35.8 million in the same period of the previous year. On a per share basis, this equaled $0.16 versus $0.18 respectively. The increase in funds from operations for the year ended June 30, 2011 is largely attributable to higher prices and production.

CAPITAL EXPENDITURES

The capital expenditures on petroleum and natural gas assets made by Southern Pacific for the year ended June 30, 2011 and 2010 are summarized in the following table:

	Twelve Months Ended June 30,	
($ thousands)	**2011**	**2010**
Land	**$ 478**	$ 45,886
Seismic, drilling and completion	**63,354**	17,011
Equipment	**13,240**	757
Capitalized interest and fees	**22,936**	–
Facilities	**137,745**	–
Access Roads	**28,951**	–
Acquisitions	**19,583**	121,784
Dispositions	**–**	(2,884)
Capital assets	**1,129**	446
Total	**$ 287,416**	$ 183,000

For the twelve months ended June 30, 2011 the Company incurred $287.4 million in capital expenditures, including $209.6 million at STP-McKay Phase 1, $15.3 million for exploration and preliminary costs associated with STP-McKay Phase 2 expansion, $18.0 million at STP-Senlac including the drilling and completion of Phase H, $2.0 million at the STP-Red Earth pilot project, $19.6 million for the North Peace acquisition and $22.9 million for capitalized interest.

FINANCING ARRANGEMENT FOR STP-MCKAY PHASE 1

On January 7, 2011, Southern Pacific completed the financing arrangements for the construction of STP-McKay Phase 1 from three sources. The Company completed a placement of a $172.5 million principal amount of 6% fixed convertible unsecured subordinated debentures. The Company also completed a US$275.0 million senior secured second lien term loan that bears interest on a floating basis at either the U.S. base rate (plus a margin 7.5% and with a floor of 2%) or LIBOR rate (plus a margin 8.5% and with a floor of 2%). It is secured on a second priority basis by substantially all the assets of the Company. Finally, Southern Pacific entered into a new credit facility which replaced its existing credit facility. The new credit facility is a $30.0 million first lien secured revolving credit facility. The new credit facility will bear interest at a floating rate plus credit spread above the reference. The Company is required to comply with financial covenants under the first and second lien facilities.

LIQUIDITY AND CAPITAL RESOURCES

As at June 30, 2011 Southern Pacific had working capital of $259.5 million. The Company has an undrawn $30.0 million demand revolving operating credit facility with a syndicate of banks. The term of the credit facility is three years and extendible at the lenders' discretion. The credit facility is guaranteed by all of the Company's subsidiaries, and secured by a security interest in all of the existing and future assets of the Company and its subsidiaries. The security interest has first priority over all other creditors.

($ thousands)	June 30, 2011
Bank lines available	**$ 30,000**
Working capital	**259,518**
Capital resources available	**$ 289,518**

Southern Pacific believes it has sufficient capital to complete its STP-McKay Project, fund budgeted capital expenditures at STP-Senlac and STP-Red Earth, fund other project development at McKay and fund exploration in its other oil sands leases from its available capital resources of $289.5 million and budgeted funds from operations over the next 12 months.

COMMITMENTS

Risk Management Activities

Oil and gas producers are exposed to fluctuations in commodity prices that are beyond the control of management. To protect cash flow for future capital programs, Southern Pacific has entered into the following commodity contracts to reduce the risk of realized oil prices and gas purchases as of September 21, 2011:

Contract Term	Type	Volume	Price
Jan 1, 2011 to Dec 31, 2011	Oil collar (WTI)	1,500 bbl/day	US$70.00-$100.00
Feb 1, 2011 to Dec 31, 2011	Oil collar (WTI)	300 bbl/day	US$85.00-$105.00
Apr 1, 2011 to Dec 31, 2011	Oil collar (WTI)	400 bbl/day	US$90.00-$115.00
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	900 bbl/day	US$85.00-$115.75
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	500 bbl/day	US$90.00-$110.00
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	700 bbl/day	US$90.00-$115.05
July 1, 2012 to Dec 31, 2012	Oil collar (WTI)	750 bbl/day	US$80.00-$101.10
Jan 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.585
Jan 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	2,000 gj/day	$ 3.93
July 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.86
July 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.84
Apr 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	500 gj/day	$ 3.24
July 1, 2011 to Aug 31, 2011	Natural gas swap purchase (AECO)	1,500 gj/day	$ 3.24
Oct 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,500 gj/day	$ 3.80
Jan 1, 2011 to Dec 31, 2011	FX contract (US$)	750 bbl/day	US$70 WTI, at 1.0620 USD/CAD
October 1 to Dec 31, 2011	FX contract (US$)	750 bbl/day	US$85 WTI, at 1.00 USD/CAD
Jan 1, 2012 to Dec 31, 2012	FX contract (US$)	750 bbl/day	US$85 WTI, at 1.00 USD/CAD

Fixed Price Contracts

As of September 21, 2011 the Company committed to the following fixed price gas purchase contracts. The contracts are entered into to reduce the risk of gas price uncertainty, as gas is a significant input cost for the Senlac operations.

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

Leases

At June 30, 2011 the Company is committed to annual lease payments under the terms of a lease for its head office space and other office spaces:

($ thousands)	Amount
2012	$ 589
2013	409
2014	409
2015	239
Total	$ 1,646

Capital

At June 30, 2011, 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 $143.3 million in capital commitments to be made over the next year.

Principal Payments

At June 30, 2011, the Company's required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

	Term loan	Convertible debentures	Total
2012	$ 2,652	$ –	$ 2,652
2013	2,652	–	2,652
2014	2,652	–	2,652
2015	2,652	–	2,652
2016	253,249	172,500	425,749
Total	$ 263,857	$ 172,500	$ 436,357

OFF BALANCE SHEET ARRANGEMENTS

Southern Pacific has not entered into any off balance sheet arrangements at June 30, 2011.

TRANSACTIONS WITH RELATED PARTIES

During fiscal 2011 the Company incurred legal costs of $0.6 million (2010 - $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, none were included in accounts payable at June 30, 2011 (2010 - $0.2 million).

OUTSTANDING SECURITIES

Common Shares, Options and Warrants

There were 2.4 million common shares issued during the year ended June 30, 2011 at a weighted average exercise price of $0.53 per share from the exercise of stock options. Additionally, 14.1 million common shares were issued for the acquisition of North Peace and 2.0 million warrants were assumed at an exercise price of $4.05. These warrants expired on December 23, 2010 and none of them were exercised.

As at June 30, 2011, 24.0 million stock options were outstanding with an average exercise price of $1.23 and 0.2 million warrants were outstanding with an average exercise price of $1.01.

At September 21, 2011, the Company has 339.5 million common shares outstanding, 24.3 million stock options outstanding and 0.2 million warrants outstanding.

Escrowed Securities

No common shares remain in escrow at June 30, 2011. During the year ended June 30, 2011, 0.2 million shares were released from escrow.

SELECTED QUARTERLY INFORMATION

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

	For the three month period ended			
($ thousands except for per share)	**June 30, 2011**	**March 31, 2011**	**December 31, 2010**	**September 30, 2010**
Net revenue	**$ 31,685**	$ 11,447	$ 18,299	$ 17,792
Net income (loss)	**10,659**	(1,417)	4,417	621
Net income (loss) per share (basic and diluted)	**$ 0.03**	$ (0.00)	$ 0.01	$ 0.00

	For the three month period ended			
($ thousands except for per share)	**June 30, 2010**	**March 31, 2010**	**December 31, 2009**	**September 30, 2009**
Net revenue	$ 18,887	$ 18,599	$ 14,784	$ 343
Net income (loss)	(1,312)	3,104	7,089	(684)
Net income (loss) per share (basic and diluted)	$ (0.00)	$ 0.01	$ 0.04	$ (0.01)

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 and Chief Financial Officer 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 Canadian GAAP.

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 2011, and has retained expert advisors to assist in the process. Based on this process, management has concluded that the Company's internal control over financial reporting was effective as of June 30, 2011.

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.

CHANGES IN AND NEW ACCOUNTING POLICIES ADOPTED

Business Combinations

Effective July 1, 2010, the Company adopted CICA Handbook section 1582, “Business Combinations”, which replaces the previous business combination standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition related and restructuring costs are recognized separately from the business combination and are included in the statement of operations. The adoption of this standard impacts the accounting treatment of business combinations entered into after July 1, 2010.

Under the previous accounting policy (CICA Handbook section 1581, “Business combinations”), the purchase price would be calculated at the effective date and would have been reduced by $4.0 million, no gain would have been recognized in the statement of operations (versus a gain of $3.6 million recognized according to CICA Handbook section 1582, see note 5(b)), as the excess of the amounts assigned to assets acquired and liabilities assumed over the cost of the purchase would have been eliminated by allocating it as a pro rata reduction of the amounts that otherwise would be assigned to the acquired assets. The transaction costs of the business combination $0.2 million would not have been recorded in the statement of operations as they would have been included in the cost of the purchase.

Consolidated Financial Statements and Non-Controlling Interests

Effective July 1, 2010, the Company adopted CICA Handbook sections 1601, Consolidated Financial Statements, and 1602, Non-controlling Interests, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of this standard impacts the accounting treatment of business combinations entered into after July 1, 2010.

FUTURE ACCOUNTING PRONOUNCEMENTS

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 adoption date for the Company of July 1, 2011 will require the restatement of comparative amounts beginning in July 2010, including an opening balance sheet as at July 1, 2010.

Management is currently evaluating the effects of all current and pending pronouncements of the International Accounting Standards Board on the financial statements of the Company and has developed a plan for implementation. The Company’s implementation plan has three components:

1. Scoping and diagnostic phase – This phase includes an analysis, on a high level, of the areas of the Company’s financial statements and systems that will be impacted by the conversion to IFRS.

2. Impact analysis and evaluation phase – This phase includes a detailed analysis of each item identified in scoping and diagnostic phase to determine the impacts on the financial statements, accounting policies and procedures, internal control procedures and external agreements.

3. Implementation phase – This phase involves the implementation of all changes in the information systems and business processes approved in the impact analysis and evaluation phase. It also includes training of staff, management and the audit committee.

Management has completed the scoping and diagnostic phase, has completed the impact analysis and evaluation phase (subject to final external review) and has substantially completed the implementation phase. Given the external review and implementation are not finalized, the Company is not yet able to quantify the impact that the adoption of IFRS will have on the financial statements.

The Company considers the following to be key differences between Canadian GAAP and IFRS that will impact the consolidated financial statements:

a) Transition Decisions
IFRS 1 "First Time Adoption of IFRS" provides certain optional exemptions for entities adopting IFRS for the first time. IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. The Company will use this exemption.

b) Exploration and Evaluation ("E&E") Expenditures
On transition to IFRS all E&E expenditures that are currently included in the Property, Plant and Equipment ("PP&E") balance on the Consolidated Balance Sheet will be re-classified. This will consist of the book value for the undeveloped land that relates to exploration properties. The E&E assets will also include costs related to on-going projects. E&E assets will not be depleted and will be assessed for impairment when indicators of impairment exist.

c) Property, Plant and Equipment
Oil and gas assets in the development and production phases, excluding the IFRS 1 adjustment, are also subject to additional and significant changes from current GAAP accounting. Such differences include items that may be expensed or capitalized, number of depletable bases and cash generating units, determination of significant components or parts within an asset, as well as the accounting treatment for disposition of assets which require the recognition of gains or losses on disposition versus the proceeds being credited to the full cost pool.

d) Depletion Expense
On transition to IFRS, Management has the option to use either proved reserves or proved and probable reserves in the depletion calculation. The Company currently anticipates that it will use proved and probable reserves for its currently producing properties.

e) Impairment of PP&E Assets
Under IFRS, impairment tests of PP&E must be performed on specific portions of PP&E as opposed to the entire PP&E balance which is currently required under Canadian GAAP through the full cost ceiling test. Impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves.

f) Decommissioning Liability (ARO)
There are also significant differences in the calculation of the ARO liability between IFRS and Canadian GAAP. The difference is primarily attributable to using a risk free rate, which is no longer credit adjusted. The Company has not yet determined the impact of the IFRS changes on the ARO liability.

g) Income Taxes
The exposure draft on income taxes was withdrawn in November 2009 and the exposure draft on IAS 37 Provisions, Contingent Liabilities and Contingent Assets was issued in January 2010. The impact of the revised standards on the transition to IFRS has been initiated but not yet completed.

The Company will be determining the impact of IFRS on internal controls over financial reporting (“ICOFR”). An assessment and review of ICOFR will be required to deal with the anticipated changes in accounting policies. This assessment will be ongoing throughout 2011 to ensure all changes in accounting policies include appropriate additional controls and procedures for future IFRS reporting requirements. To date, no significant changes have been noted.

In regards to disclosure controls and procedures, the Company will be assessing stakeholders’ information requirements and will ensure that appropriate and timely information is provided once available. At this time, specific changes to disclosure controls and procedures have not been determined however, significant changes are not anticipated.

The Company has identified resource requirements that will be necessary for the development of IFRS expertise within the organization. Training of key operational and financial staff has been ongoing throughout 2011. The Company has held a preliminary IFRS information session with the Board of Directors, which included the audit committee members. During this session, management provided a review of the timeline for implementation and significant changes as a result of the new IFRS accounting standards. The audit committee has received regular progress reports on the IFRS conversion.

An assessment of the Company’s infrastructure, primarily information technology and data systems, 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.

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.

Impairment of Property and Equipment

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

Withheld Costs

Certain costs related to unproved properties and major project developments related to the Company’s oil sands assets may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation and in the ceiling test for impairment for which any write-down would be charged to a depletion and depreciation expense.

Asset Retirement Obligations

When Southern Pacific has drilled core holes, it has properly abandoned them within the drilling program and therefore, no asset retirement 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 asset retirement obligations is recorded in the period in which it is to be incurred and discounted to its present value using the Company's credit adjusted 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.

Depletion Expense

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 total proved petroleum and natural gas reserves as estimated by independent engineers. In determining costs subject to depletion, Southern Pacific includes estimated future costs to be incurred in developing proved reserves and excludes salvage value. The costs of undeveloped properties are excluded from the costs subject to depletion until it is determined that proved reserves are attributable to the property or impairment has occurred.

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 and risk-free 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 and the risk-free rate is obtained from the Bank of Canada. An increase in dividends 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 sued 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 forecast interest and foreign exchange rates 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.

BOE PRESENTATION

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

NOTE REGARDING NON-GAAP MEASURES

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

	Three Months Ended June 30,		Twelve Months Ended June 30,	
($ thousands)	**2011**	**2010**	**2011**	**2010**
Cash provided by operations	**$ 5,478**	$ 12,420	**$ 43,933**	$ 33,804
Change in non-cash working capital	**12,234**	(613)	**7,656**	1,920
Cash abandonment expenditures	**231**	30	**283**	49
Funds from operations	**$ 17,943**	$ 11,837	**$ 51,872**	$ 35,773

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, 2010, 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, the possibility of cost overruns or unanticipated costs and expenses, regulatory approvals, changes to royalty regimes, fluctuating commodity prices and currency exchange rates and the ability to access sufficient capital from external sources to finance future development. As a consequence, actual results may differ, and may differ materially, from those anticipated in the forward-looking statements. The reader is cautioned not to place undue reliance on these forward-looking statements as there can be no assurance that such plans, intentions or expectations upon which they are based will occur. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this MD&A are made as of the date of this MD&A and state no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise, expect as required by applicable securities laws.

RISK FACTORS

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

MANAGEMENT'S RESPONSIBILITY

To the Shareholders of Southern Pacific Resource Corp.:

Management is responsible for the preparation and presentation of the accompanying financial statements, including responsibility for significant accounting judgments and estimates in accordance with Canadian generally accepted accounting principles. This responsibility includes selecting appropriate accounting principles and methods, and making decisions affecting the measurement of transactions in which objective judgment is required.

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 21, 2011

Howard Bolinger
Chief Financial Officer
September 21, 2011

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Southern Pacific Resource Corp.:

We have audited the accompanying financial statements of Southern Pacific Resource Corp., which comprise the consolidated balance sheets as at June 30, 2011 and 2010 and the consolidated statements of operations, comprehensive income and retained earnings (deficit) and cash flows for the years then ended, and the notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

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

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 audits 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, these consolidated financial statements present fairly, in all material respects, the financial position of Southern Pacific Resource Corp. as at June 30, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta
September 21, 2011

CONSOLIDATED BALANCE SHEETS

As at June 30, (Stated in thousands of Canadian dollars)	2011	2010
Assets		
Current assets		
Cash and cash equivalents	**$ 322,927**	$ 63,505
Accounts receivable	**13,091**	7,377
Prepaid expenses and deposits	**1,157**	232
Risk management contracts (note 15(b))	**570**	273
	337,745	71,387
Property, plant and equipment (note 6)	**533,615**	277,810
	871,360	349,197
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**75,574**	11,458
Current portion of long term-term debt (note 7)	**2,652**	–
	78,226	11,458
Long-term debt (note 7)	**374,186**	–
Asset retirement obligations (note 8)	**10,043**	6,449
Future income tax (note 9)	**38,201**	39,770
	500,656	57,677
Shareholders' equity		
Share capital (note 10)	**304,476**	281,579
Equity component of convertible debentures (note 7)	**40,344**	–
Contributed surplus (note 11)	**24,884**	23,221
Retained earnings (Deficit)	**1,000**	(13,280)
	370,704	291,520
	$ 871,360	$ 349,197

Commitments (note 16)

See accompanying notes to financial statements.

On behalf of the Board:

Signed "David M. Antony"

David M. Antony, Director

Signed "Kenneth N. Cullen"

Kenneth N. Cullen, Director

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME AND RETAINED EARNINGS (DEFICIT)

Years ended June 30, (Stated in thousands of Canadian dollars, except per share amounts)	2011	2010
Revenue		
Petroleum and natural gas	**$ 93,727**	$ 62,043
Royalties	**(15,274)**	(9,642)
Gain on risk management contracts (note 15(b))	**286**	198
Interest and other	**484**	15
	79,223	52,614
Expenses		
Operating	**15,680**	10,656
General and administrative	**9,527**	4,064
Interest and financing (note 7(a))	**326**	947
Depletion, depreciation and accretion	**34,856**	28,598
Stock based compensation	**3,144**	3,203
	63,533	47,468
Other		
Gain on foreign exchange	**1,102**	–
Gain on acquisition (note 5(a))	**3,585**	–
	4,687	–
Income before income taxes	**20,377**	5,146
Income taxes (note 9)		
Saskatchewan resource surchages	**1,588**	901
Future expense (recovery)	**4,509**	(3,952)
	6,097	(3,051)
Net income and comprehensive income	**14,280**	8,197
Deficit, beginning of year	**(13,280)**	(21,477)
Retained earnings (deficit), end of year	**$ 1,000**	$ (13,280)
Net income per share - basic and diluted	**0.04**	0.04
Weighted average number of shares outstanding (Stated in thousands):		
Basic	**331,902**	200,385
Diluted (note 10(e))	**$ 338,834**	$ 202,751

See accompanying notes to financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended June 30, (Stated in thousands of Canadian dollars)	2011	2010
Cash provided by (used in)		
Operations:		
Net income	**$ 14,280**	$ 8,197
Items not effecting cash		
Depletion, depreciation and accretion	**34,856**	28,598
Future income taxes (recovery)	**4,509**	(3,952)
Unrealized gain on risk management contracts (note 15)	**(297)**	(273)
Unrealized gain on foreign exchange (note 15)	**(1,035)**	–
Stock based compensation	**3,144**	3,203
Gain on acquisition (note 5(a))	**(3,585)**	–
	51,872	35,773
Net change in non-cash working capital	**(7,656)**	(1,920)
Cash abandonment expenditures (note 8)	**(283)**	(49)
	43,933	33,804
Financing:		
Issue of common shares, net of costs (note 10)	**1,263**	151,513
Issue of long term debt, net of costs (note 7)	**421,796**	–
Repayment of long term debt (note 7)	**(1,335)**	–
Repayment of bank debt	**–**	(1,730)
	421,724	149,783
Investments:		
Petroleum and natural gas expenditures	**(263,764)**	(45,842)
Corporate acquisitions, net of cash acquired (note 5)	**72**	(89,331)
Petroleum and natural gas dispositions	**–**	2,884
Net change in non-cash working capital	**64,415**	5,619
	(199,277)	(126,670)
Net increase in cash and cash equivalents	**266,380**	56,917
Foreign exchange loss on cash balances	**(6,958)**	–
Cash and cash equivalents, beginning of year	**63,505**	6,588
Cash and cash equivalents, end of year	**$ 322,927**	$ 63,505

Supplementary cash flow information (note 13).

See accompanying notes to financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(All tabular amounts stated in thousands except per share amounts)
Years ended June 30, 2011 and 2010

1. INCORPORATION AND NATURE OF OPERATIONS:

Southern Pacific Resource Corp., its subsidiaries; Southern Pacific Energy Ltd., Senlac Oil Ltd., Southern Pacific Resource Partnership, 1539148 Alberta Ltd., 1614789 Alberta Ltd. and North Peace Energy Corp. (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 in Calgary, Alberta, Canada and its shares trade on the Toronto Stock Exchange "TSX" under the symbol "STP".

The Company is involved in the exploration and development of in-situ oil sands properties located in northern Alberta, Canada and develops and produces heavy oil, conventional petroleum and natural gas in western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES:

(a) Principles of Consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and partnerships. All intercompany transactions and balances have been eliminated upon consolidation. Operations of acquired businesses (note 5) 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) Property, Plant and Equipment:

The Company follows the full cost method of accounting for its petroleum and natural gas and bitumen reserves whereby all costs associated with the acquisition of, exploration for and development of reserves, including asset retirement obligations are capitalized and accumulated in one cost centre. Costs capitalized include land acquisition costs, geological and geophysical expenditures, costs of drilling productive and non productive wells, and lease and well equipment. Proceeds from disposition of petroleum and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition would alter the depletion and depreciation rate by 20% or more.

To date, all direct costs relating to the development of the oil sands properties are capitalized, including the cost of the acquisition of leases, exploration and evaluation costs that are directly related to development activities. When production begins, these capitalized costs will be amortized following the unit-of-production method based on total proved reserves. The Company capitalizes the carrying costs, including the interest and financing transaction costs on long-term debt for undeveloped property acquisitions and major development projects.

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 total proved 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 proved reserves and excludes salvage value. The cost of undeveloped properties are excluded from the costs subject to depletion until it is determined that proved reserves are attributable to the property or impairment has occurred. The costs of major development projects are also excluded from depletion until the development activity ceases or the project is completed. 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.

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 ranging from 30% to 50% which are designed to amortize the cost over their estimated useful lives.

Under the full cost method of accounting, a "ceiling test" is performed to recognize and measure impairment, if any, of the carrying amount of petroleum and natural gas properties. Impairment is recognized if the carrying amount of petroleum and natural gas properties, less the cost of undeveloped properties not subject to depletion, exceeds the estimated undiscounted future cash flows from the Company's proved reserves. The future cash flows are based on a forecast of prices, as provided by independent engineers. If recognized, the magnitude of the impairment is then measured by comparing the fair value of the Company's proved and probable reserves to their carrying values.

The Company performs impairment testing on its unproved properties and major development projects at least annually and whenever events or changes in circumstances indicate that the carrying value of an asset, or group of assets, may not be recoverable. Long lived assets are tested for impairment by comparing the estimate of undiscounted future cash flows to the carrying amount of the assets or group of assets. If the carrying value is not recoverable from undiscounted future expected cash flows, any loss is measured as the amount by which the asset's carrying value exceeds fair value, and recorded in the period.

(d) 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.

(e) Stock Based Compensation:

Stock options issued are accounted for in accordance with fair value accounting for stock-based compensation. The associated stock compensation expense is charged to the statement of operations with a corresponding increase to contributed surplus, over the vesting period of the option. The fair value of each stock option granted is estimated on the date of grant using a Black–Scholes option pricing model. 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 and no stock based compensation is recorded on these options in future periods and any unvested stock based compensation in the current period is reversed. In the event that unvested options are cancelled, previously recognized compensation expense associated with such stock options is reversed.

(f) Per Share Amounts:

Basic net earnings per share is calculated using the weighted average number of common shares outstanding during the year. 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.

(g) Income Taxes:

The Company follows the liability method of accounting for income taxes. Under this method, future 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. In addition, the future benefits of income tax assets, including unused tax losses, are recognized, subject to a valuation allowance, to the extent that it is more likely than not that such future benefits will ultimately be realized. Future 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.

(h) Joint Interest Operations:

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

(i) 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 balance sheet 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) held-for-trading assets and liabilities. Financial instruments classified as held-for-trading or available-for-sale items as a result of initially adopting this section are measured at fair value. Gains or losses on subsequent measurement of held-for-trading items are recognized in net income (loss), while gains and losses on subsequent measurement of available-for-sale items are recognized in other comprehensive income.

At June 30, 2011, the Company's financial instruments include cash and cash equivalents, accounts receivable, risk management contracts, accounts payable and accrued liabilities and long term debt. Cash and cash equivalents are measured at fair value consistent with the "assets held-for-trading" classification. Net gains and losses arising from changes in fair value are recognized in net income upon derecognition or impairment. 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. Accounts payable and accrued liabilities and long term debt are measured at amortized cost using the effective interest method, consistent with the "other financial liabilities" classification.

The Company enters into certain financial derivative contracts in order to reduce its exposure to market risks from fluctuations in commodity prices, foreign currency and interest rates. These instruments are not used for speculative purposes. 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 "held-for-trading" and recorded on the balance sheet at fair value at each reporting date. Realized and unrealized gains and losses on these contracts are recognized in net income. Attributable transaction costs are recorded in the statement of operations.

The Company does not have any items related to comprehensive income for the year ended June 30, 2011 or 2010; and accordingly, comprehensive income is equivalent to net income.

(j) Use of Estimates:

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reporting amount of revenues and expenses during the reporting period. Accounts receivable are stated after evaluation as to their collectability and an appropriate allowance for doubtful accounts is provided where considered necessary. Amounts for stock based compensation are based upon estimates of risk-free rates, expected lives and volatility. Amounts recorded for depletion of resource properties, amortization of property and equipment, asset retirement obligations and impairment calculations are based on estimates of natural gas and crude oil 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, and the impact in the financial statements of future periods could be material. These estimates are reviewed periodically and as adjustments become necessary, they are reported in earnings in the period in which they become known. Actual results could differ significantly from those estimates.

The consolidated financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements the accruals made by management in this regard may be different from those determined by the Corporation's joint venture partners. The effect on the consolidated financial statements resulting from such adjustments, if any, will be reflected prospectively.

Computations of provisions and estimates for income taxes involve management making judgments with respect to interpretations of tax regulations and related legislation which is continually changing. In addition, there are tax matters that have not yet been confirmed by taxation authorities. While management believes the provision for income taxes is adequate, these amounts are subject to measurement uncertainty. Adjustments required, if any, to these provisions will be reflected in the period that it is determined that adjustments are warranted.

(k) Asset Retirement Obligations:

The Company records the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the assets. The associated asset retirement 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 reserves. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each period to reflect the passage of time (accretion) and changes in the estimated future cash flows underlying the obligation. Actual abandonment restoration expenditures are charged to the asset retirement obligation as incurred, with any remainder recorded to earnings as a gain or loss.

(l) 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.

(m) Financing Transactions Costs:

Financing transaction costs associated with the issuance of long-term debt are included as a component of the debt value and are amortized over the life of the debt utilizing the effective interest rate method.

(n) Convertible Debentures:

On initial recognition, the convertible debentures were classified into debt and equity components at fair value. The fair value of the liability component was determined as the present value of the principal and interest payments, discounted using the Company's incremental borrowing rate for debt with similar terms but without a conversion feature. The amount of the equity component was determined as a residual, after deducting the amount of the liability component from the face value of the debentures. 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.

(o) Comparative Figures:

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

3. CHANGES IN AND NEW ACCOUNTING POLICIES ADOPTED:

(a) Business Combinations:

Effective July 1, 2010, the Company early adopted CICA Handbook section 1582, "Business Combinations", which replaces the previous business combination standard. The standard requires that assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies are measured at their fair values as of the closing date of acquisition. In addition, acquisition related and restructuring costs are recognized separately from the business combination and are included in the statement of operations. The adoption of this standard impacts the accounting treatment of business combinations entered into after July 1, 2010 (see note 5(b)).

Under the previous accounting policy (CICA Handbook section 1581, "Business combinations"), the purchase price would be calculated at the effective date and would have been reduced by $4.0 million, no gain would have been recognized in the statement of operations (versus a gain of $3.6 million recognized according to CICA Handbook section 1582, see note 5(b)), as the excess of the amounts assigned to assets acquired and liabilities assumed over the cost of the purchase would have been eliminated by allocating it as a pro rata reduction of the amounts that otherwise would be assigned to the acquired assets. The transaction costs of the business combination $0.2 million would not have been recorded in the statement of operations as they would have been included in the cost of the purchase.

(b) Consolidated Financial Statements and Non-Controlling Interests:

Effective July 1, 2010, the Company adopted CICA Handbook sections 1601, Consolidated Financial Statements, and 1602, Non-controlling Interests, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of these standards has not had a significant impact on the Company's financial statements.

4. FUTURE ACCOUNTING PRONOUNCEMENTS – INTERNATIONAL FINANCIAL REPORTING STANDARDS:

In October 2009, CICA confirmed that publicly accountable enterprises in Canada will be required to apply International Financial Reporting Standards "IFRS" beginning on or after January 1, 2011. Effective July 1, 2011, the Company will be required to report its consolidated financial statements in accordance with IFRS and restate the comparative information for the year ended June 30, 2011 and of the opening balance sheet as at July 1, 2010.

5. CORPORATE ACQUISITIONS:

(a) 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 1,952,582 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 (except for the future income tax asset determined in accordance with CICA Handbook section 3465) and liabilities acquired as follows:

Allocation of purchase price	
Petroleum and natural gas assets	**$ 19,462**
Working capital deficiency including cash of $72	**(647)**
Future income tax	**5,555**
Asset retirement obligation	**(632)**
	$ 23,738
Calculation of purchase price	
Common shares issued (14,093 shares)	**20,153**
Gain on acquisition	**3,585**
	$ 23,738

(b) Acquisition of Senlac Oil Ltd.:

On November 3, 2009, the Company acquired all of the outstanding common shares of Senlac Oil Ltd. ("Senlac"). The Senlac acquisition was accounted for by the purchase method and the shares were acquired for $89.7 million. At the date of acquisition, income taxes payable were estimated at $1.1 million. Subsequently, income taxes payable were finalized and determined to be $1.4 million. The change has been reflected in the purchase price allocation. 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	**$ 129,376**
Working capital including cash of $10	**1,312**
Income taxes payable	**(1,422)**
Asset retirement obligation	**(7,654)**
Future tax liability	**(31,950)**
	$ 89,662
Calculation of purchase price	
Cash	**88,946**
Transaction costs including non-cash stock based compensation of $320(1) (note 11)	**716**
	$ 89,662

(1) Stock based compensation on 654,999 stock options issued to Senlac employees were determined to have a fair value of $0.49 per share which was attributed to the purchase price. The exercise price of the stock options issued was $0.56.

(All tabular amounts stated in thousands except per share amounts)
Years ended June 30, 2011 and 2010

6. PROPERTY, PLANT AND EQUIPMENT:

June 30, 2011	**Cost**	**Accumulated Depletion/ Amortization**	**Net book value**
Petroleum and natural gas assets	**$ 594,958**	**$ (62,612)**	**$ 532,346**
Capital assets	**1,697**	**(428)**	**1,269**
	$ 596,655	**$ (63,040)**	**$ 533,615**

June 30, 2010	**Cost**	**Accumulated Depletion/ Amortization**	**Net book value**
Petroleum and natural gas assets	$ 305,813	$ (28,411)	$ 277,402
Capital assets	568	(160)	408
	$ 306,381	$ (28,571)	$ 277,810

Costs related to development of oil sands properties and undeveloped lands have been excluded from the depletion calculation. As at June 30, 2011, the total of such costs was $442.0 million (2010 - $172.5 million) including $1.4 million (2010 – $1.3 million) of undeveloped land costs. Future development costs on proven undeveloped conventional oil and gas reserves of $68.6 million (2010 - $74.7 million) are included in the depletion calculation.

During the year ended June 30, 2011 the Company capitalized $0.6 million (June 30, 2010 – Nil) of general and administrative expenses and $22.9 million of interest and debt service costs relating to oil sands exploration and development.

On June 1, 2010, the Company purchased the remaining 20% working interest in the oil sands property at McKay and Ells for $33.7 million, consisting of $27.3 million in cash and the issuance of 6,470,588 shares at a deemed value of $1.02 per share. The Company recognized a future income tax liability of $11.9 million on purchase of these properties and a corresponding increase to property plant and equipment.

The Company's oil sands, crude oil and natural gas reserves were evaluated by qualified independent evaluators as at June 30, 2011 using the following base price assumptions. Based on these assumptions, the Company completed a ceiling test of its oil sands, crude oil and natural gas properties and equipment and determined no impairment was indicated.

	Heavy Oil Wellhead Current ($CDN/bbl)	**WTI at Cushing ($US/bbl)**	**Alberta Spot ($CDN/ mmbtu)**
2011	$ 64.00	$ 97.50	$ 3.85
2012	63.47	100.00	4.37
2013	61.77	100.00	4.82
2014	64.76	100.00	5.28
2015	65.71	100.00	5.73
2016	65.40	100.00	6.19
2017	66.26	101.36	6.51
2018	67.61	103.38	6.66
2019	68.85	105.45	6.81
2020	$ 70.03	$ 107.56	$ 6.96
2021+	+2%/yr	+2%/yr	+2%/yr

7. LONG-TERM DEBT:

	Note	June 30, 2011	June 30, 2010
Revolving credit facility (CDN$30 million)	(a)	**$ –**	$ –
Second lien term loan (US$273.6 million)		**263,857**	–
Financing transaction costs on second lien term loan		**(15,867)**	–
Amortization of financing costs		**1,252**	
Less current portion of second lien term loan		**(2,652)**	–
	(b)	**$ 246,590**	$
Convertible debentures (CDN$172.5 million)		**172,500**	–
Financing transaction costs on convertible debentures		**(6,082)**	–
Amortization of financing costs		**374**	
Equity component of convertible debentures		**(40,344)**	
Amortization of equity component		**1,148**	
	(c)	**$ 127,596**	$ –
Long-term debt		**$ 374,186**	$

(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. This new facility replaced the Company's previous facility of $55 million. 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, 2011, $1.3 million of letters of credit were issued and outstanding pursuant to the facility. As such, the Company has $28.7 million available under the facility. For the year ending June 30, 2011 $0.3 million (2010 - $0.9 million) was incurred in interest and finance fees.

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

- a minimum EBITDA (defined as earnings before finance charges, taxes, depletion, depreciation, accretion, risk management contract gains or losses, stock based compensation expenses and foreign exchange gains and losses) covenant during the construction period of the STP-McKay project of not less than US$35 million based on the 12 months trailing EBITDA;
- a PV-10 (pre-income tax present value of future cash flows from proved and probable reserves utilizing a 10% discount rate) to secured debt ratio starting at 1.75:1 and increasing to 3.00:1 during the term of the facility;
- a secured leverage ratio (the ratio of the term loan and facility debt to the last 12 months trailing EBITDA) after completion of STP-McKay 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, 2011.

(b) Second Lien Term Loan (due January 7, 2016):

The Company raised US$275 million under a second lien term loan ("term loan"). 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%. The term loan requires scheduled quarterly payments of accrued interest and principal payments 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. The effective annualized interest rate for the year ended June 30, 2011 was 12.9% which includes interest and amortization of the applicable financing costs.

The term loan contains various non-financial covenants that, among other things, restrict the Company with respect to issuing additional debt, making investments and loans, paying dividends, altering the nature of the business and undertaking corporate transactions. The term loan is subject to the same covenants as the facility discussed in note 7(a) except that it does not include a debt to EBITDA ratio covenant. The Company is in compliance with all covenants under the term loan as of June 30, 2011.

At any time prior to January 7, 2016, the Company may prepay all or part of the term loan. The prepayment premium is 112% in year one, is 102% in year 2, is 101% in year 3 and par in years 4 and 5 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, 2011.

As at June 30, 2011, US$50 million of the funds from the term loan is held in a separate collateral escrow account with the lender. These funds are available for use providing the Company is not in default of its covenants. After the completion of STP-McKay project, the Company is permitted to use any funds remaining in the deposit account to prepay amounts owing under the term loan at par.

The term loan is translated into Canadian dollars at the period end exchange rate of $1 CAD = $0.9643 US. The unrealized foreign exchange gain of $8.0 million (note 15(f)) on the term loan was recognized in earnings as a component of gain on foreign exchange.

(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. 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 $6.1 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 $40.3 million (net of related transaction costs of $1.9 million and future income tax adjustments of $0.5 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 13.6%.

(d) Required Debt Principal Payments:

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

	Term loan	Convertible debentures	Total
2012	$ 2,652	$ –	**$ 2,652**
2013	2,652	–	**2,652**
2014	2,652	–	**2,652**
2015	2,652	–	**2,652**
2016	253,249	172,500	**425,749**
Total	$ 263,857	$ 172,500	**$ 436,357**

8. ASSET RETIREMENT OBLIGATIONS:

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

	2011	2010
Balance, beginning of year	**$ 6,449**	$ 1,001
Liabilities assumed on acquisition	**632**	7,655
Additions and dispositions	**2,306**	(111)
Effect of change in estimates	**552**	(2,468)
Abandonment costs	**(283)**	(49)
Accretion expense	**387**	421
Balance, end of year	**$ 10,043**	$ 6,449

The total undiscounted amount of estimated cash flows required to settle the obligation is $56.1 million (2010 - $14.4 million), which has been discounted using a credit adjusted risk free rate of 8% and an inflation rate of 2.5%. Settlements will be funded from general corporate resources at the time of the properties' retirement and removal during the next 2 to 41 years.

(All tabular amounts stated in thousands except per share amounts)
Years ended June 30, 2011 and 2010

9. FUTURE INCOME TAXES:

The income tax provision differs from income taxes which would result from applying the expected tax rate to net income before income taxes. The differences between the "expected" income tax expense and the actual income tax provision for the years ended June 30 are summarized as follows:

	2011	2010
Net income before income taxes	**$ 20,377**	$ 5,146
Statutory income tax rate	**29.0%**	30.0%
Expected income tax expense (recovery)	**5,909**	1,544
Differences resulting from:		
Stock-based compensation	**912**	961
Rate adjustments	**(1,981)**	(1,764)
Non-taxable gain on foreign exchange	**(1,159)**	–
Finance fees	**744**	–
Other	**241**	(237)
Tax effect of gain on acquisition	**(1,011)**	–
Change in valuation allowance	**854**	(4,456)
Saskatchewan resource surchages	**1,588**	901
Income tax (recovery)	**$ 6,097**	$ (3,051)

The components of the future income liability are as follows:

	2011	2010
Future income tax assets (liabilities):		
Book value in excess of tax basis of assets	**$ (55,363)**	$ (42,796)
Non-capital losses	**37,362**	9,069
Asset retirement obligations	**2,611**	1,741
Share issue costs	**2,153**	3,043
Valuation allowance	**(9,539)**	–
Deferred partnership income	**(14,239)**	(10,753)
Unrealized gains/losses	**(1,038)**	–
Risk management contracts	**(148)**	(74)
	$ (38,201)	$ (39,770)

As at June 30, 2011, the Company has total income tax pools of approximately $456.3 million (June 30, 2010 $164.2 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 $143.7 million (June 30, 2010 - $33.6 million) which expire, as follows:

	Amount
2014	$ 522
2015	1,623
2026	1,816
2027	2,768
2028	5,900
2029	13,773
2030	117,299
Total	$ 143,701

10. SHARE CAPITAL:

(a) Authorized:

Unlimited common shares without par value.

Unlimited first preferred shares without par value.

(b) Common Shares Issued:

	Number of shares	Amount
Balance, June 30, 2009	121,611	$ 120,994
Exercise of options	313	138
Issued for cash [(1)]	194,300	160,360
Issued for property acquired [(2)]	6,471	6,600
Share issue costs (net of future income tax - $2.4 million)	–	(6,513)
Balance, June 30, 2010	322,695	281,579
Exercise of options	**2,421**	**2,775**
Cancelled [(3)]	**(42)**	**–**
Share issue costs	**–**	**(31)**
Acquisition of North Peace (Note 5(a))	**14,093**	**20,153**
Balance, June 30, 2011	**339,167**	**$ 304,476**

(1) During the year ended June 30, 2010, the Company issued 104,000,000 common shares at $0.50 per common share for gross proceeds of $52.0 million and share issuance costs of $3.3 million.

Also, during the year ended June 30, 2010, the Company issued 90,300,000 common shares at a price of $1.20 per common share for gross proceeds of $108.4 million and share issuance costs of $5.6 million.

(2) During the year ended June 30, 2010, the Company issued 6,470,588 shares at $1.02 per share to purchase the remaining 20% working interest in the oil sands property at Mckay and Ells.

(3) 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.

At June 30, 2011, no (June 30, 2010, 172,000) common shares remain in escrow.

(c) Stock Options:

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

	Number of options	Weighted Average Exercise Price
Balance, June 30, 2009	9,762	$ 1.32
Granted	10,229	0.78
Forfeited	(128)	1.28
Expired	(155)	2.13
Exercised	(313)	0.24
Balance, June 30, 2010	**19,395**	**1.05**
Granted	**7,574**	**1.51**
Forfeited	**(549)**	**1.84**
Exercised	**(2,421)**	**0.53**
Balance, June 30, 2011	**23,999**	**$ 1.23**

(All tabular amounts stated in thousands except per share amounts)
Years ended June 30, 2011 and 2010

The following table summarizes information about the stock options outstanding at June 30, 2011:

Range of exercise price (per share)	Options	Outstanding Weighted Average Exercise Price	Outstanding Weighted Average Remaining Life (Years)	Options	Exercisable Weighted Average Exercise Price	Exercisable Weighted Average Remaining Life (Years)
$0.10 - $0.15	1,320	$0.10	2.47	1,320	$0.10	2.47
$0.50 - $0.75	5,926	0.55	2.96	5,927	0.55	2.96
$0.77 - $1.15	3,626	0.97	2.94	2,990	0.96	2.68
$1.17 - $1.75	8,752	1.43	4.63	833	1.20	4.00
$1.76 - $1.92	2,975	1.89	2.09	2,450	1.90	1.52
$3.15 - $3.15	1,400	3.15	1.00	1,400	3.15	1.00
	23,999	$1.23	3.32	14,920	$1.10	2.50

The weighted average fair value of the options granted during the year is estimated at $0.80 (2010 – $0.70) on the dates of grant using a Black-Scholes option pricing model with the following assumptions:

	2011	2010
Risk free interest rate	**2.4%**	2.4%
Expected life in years	**4.5**	4.3
Expected volatility	**122.0%**	128.0%
Dividend yield	**0.0%**	0.0%

(d) Warrants:

Warrant transactions are summarized as follows:

	Number of Warrants	Weighted Average Exercise Price
Balance, June 30, 2009	3,444	$ 2.70
Expired	(1,317)	3.95
Balance, June 30, 2010	**2,127**	**1.93**
Warrants assumed on acquisition (Note 5(a))	**1,953**(1)	**4.05**
Expired	**(3,891)**	**3.04**
Balance, June 30, 2011	**189**(2)	**$ 1.01**

(1) The warrants expired unexercised on December 23, 2010.

(2) At June 30, 2011, 189,000 warrants are exercisable at $1.01 and expire on March 23, 2012.

(e) Per Share Amounts:

The Company excluded 6,325,000 options (2010 – 17,028,679) and no warrants (2010 – 2,126,807) from the calculation of the weighted average number of shares as they were anti-dilutive.

11. CONTRIBUTED SURPLUS:

	2011	2010
Balance, beginning of year	$ 23,221	$ 19,762
Options exercised	(1,481)	(64)
Acquisitions (Note 5(b))	–	320
Stock-based compensation	3,144	3,203
Balance, end of year	$ 24,884	$ 23,221

12. RELATED PARTY TRANSACTIONS:

During 2011, the Company incurred legal costs of $0.6 million (2010 - $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, none were included in accounts payable at June 30, 2011 (2010 - $0.2 million).

13. SUPPLEMENTAL CASH FLOW INFORMATION:

	2011	2010
Interest and finance fees paid (1)	$ 18,982	$ 947
Provincial income taxes paid	$ 1,666	$ 805

	2011	2010
Cash	$ 274,687	$ 63,505
Term deposits	48,240	–
Cash and cash equivalents	$ 322,927	$ 63,505

(1) The non-cash portion of interest and financing fees, not included in the above balance, is $3.9 million related to the accretion of the financing fees and equity portion of the convertible debt.

14. 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 oil sands resources and development of its existing producing properties. The Company is using a phased approach for development of its oil-sands leases which is designed to reduce project capital investment.

During the year, the Company changed how it defined its capital structure to exclude working capital. The Company considers its capital structure to include shareholders' equity and long term debt which totals $743.5 million at June 30, 2011 (June 30, 2010 - $291.5 million). The Company's in-situ oil sands 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 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 covenants under long-term (Note 7). The Company has not paid or declared dividends since its reorganization of management and change in principal business on March 2, 2006.

(All tabular amounts stated in thousands except per share amounts)
Years ended June 30, 2011 and 2010

15. FINANCIAL INSTRUMENTS:

Financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, risk management contracts and long term debt. The Company is exposed to the following risks in respect of certain financial instruments held:

(a) Credit Risk

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

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

As at June 30, 2011, accounts receivable includes a balance of $0.1 million (June 30, 2010 - $0.5 million) over 90 days, which is considered to be past due. As at June 30, 2011 $0.3 million (June 30, 2010 - $0.0 million) of an allowance for doubtful accounts has been recorded on certain aged receivables.

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, 2011 were held with two banking institution in Canada; $48.2 million with one and $274.7 million with the other. The Corporation periodically monitors published and available credit information for all of it's 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, 2011 the fair value is estimated to be an unrealized gain of $0.6 million (2010 - $0.3 million). The following table summarizes the change in fair value of the Company's risk management contracts:

	2011	2010
Balance, beginning of year	**$ 273**	$ –
Unrealized gain during the year	**297**	273
Balance, end of year	**$ 570**	$ 273

The Company has the following contracts outstanding as of June 30, 2011:

Contract Term	Type	Volume	Price
Jan 1, 2011 to Dec 31, 2011	Oil collar (WTI)	1,500 bbl/day	US$70.00-$100.00
Feb 1, 2011 to Dec 31, 2011	Oil collar (WTI)	300 bbl/day	US$85.00-$105.00
Apr 1, 2011 to Dec 31, 2011	Oil collar (WTI)	400 bbl/day	US$90.00-$115.00
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	900 bbl/day	US$85.00-$115.75
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	500 bbl/day	US$90.00-$110.00
Jan 1, 2012 to June 30, 2012	Oil collar (WTI)	700 bbl/day	US$90.00-$115.05
Jan 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.585
Jan 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	2,000 gj/day	$ 3.93
July 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.86
July 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,000 gj/day	$ 3.84
Apr 1, 2011 to June 30, 2011	Natural gas swap purchase (AECO)	500 gj/day	$ 3.24
July 1, 2011 to Aug 31, 2011	Natural gas swap purchase (AECO)	1,500 gj/day	$ 3.24
Oct 1, 2011 to Dec 31, 2011	Natural gas swap purchase (AECO)	1,500 gj/day	$ 3.80
Jan 1, 2011 to Dec 31, 2011	FX contract (US$)	750 bbl/day	US$70 WTI, at 1.0620 USD/CAD

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

	2011	2010
Unrealized gain (loss)	**$ 298**	$ 273
Realized gain (loss)	**(12)**	(75)
	$ 286	$ 198

As at June 30, 2011, had the forward price for WTI been US$1.00/bbl higher or lower, the impact relating to the oil collar risk management contracts would have been no change in net earnings before income taxes (2010 – $0.0 million).

As at June 30, 2011, 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 earnings before income taxes of $0.2 million (2010 – $0.1 million).

As at June 30, 2011, 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 earnings before income taxes of $0.1 million (2010 - $0.0 million).

(c) Liquidity Risk

Liquidity risk is the 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, pre-funds major development projects in staged phases, monitors budgets to control costs, and monitors its operating cash flow and working capital.

(All tabular amounts stated in thousands except per share amounts)

(d) Fair Value

The financial instruments recognized in the balance sheet are comprised of cash and cash equivalents, accounts receivable, risk management contracts, accounts payable and accrued liabilities and long-term debt. The carrying value of accounts receivable and accounts payable and accrued liabilities approximate the fair value of the respective assets and liabilities due to the short term nature of those instruments. The risk management contracts are recognized on the balance sheet at a Level 2 fair value which is discussed above in note 15(b). Long-term debt is carried at amortized cost and the fair value, based on current market prices, is estimated to be $447.6 million, consisting of the term loan of $268.5 million and the convertible debentures of $179.1 million, including the equity component, based on current market prices.

(e) Interest Rate Risk

The Company is exposed to interest rate fluctuations on its term loan and its revolving credit facility which bear a floating rate of interest (Note 7).

(f) Currency Risk:

The Company is exposed to fluctuations in foreign currency primarily as a result of its U.S. dollar denominated second lien term loan facility, crude oil sales based on U.S. dollar indices and commodity price contracts that are settled in U.S. dollars. As at June 30, 2011, a $0.01 change in the US to Canadian dollar exchange rate would have resulted in a change in net earnings before income taxes of $0.6 million (2010 - $0.0 million). The Company had working capital as of June 30, 2011 denominated in U.S. dollars of $214.4 million (2010 - $0.0 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 foreign exchange gain (loss):

	2011	2010
Unrealized foreign exchange gain (loss) on translation of:		
U.S. denominated second term loan facility	$ 7,993	$ –
Foreign currency denominated cash balances	(6,958)	–
Unrealized foreign exchange gain	$ 1,035	$ –

16. COMMITMENTS:

At June 30, 2011 the Company is committed to annual lease payments, under the terms of a lease for its head office space and other office spaces:

	Amount
2012	$ 589
2013	409
2014	409
2015	239
Total	$ 1,646

At June 30, 2011, 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 $143.3 million in capital expenditure commitments to be made over the next year.

At June 30, 2011, as part of normal operations, the Company has entered into the following fixed price gas purchase contracts:

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

CORPORATE INFORMATION

Officers

Byron Lutes, P.ENG. – President and Chief Executive Officer

Ron Clarke, P.ENG. – Chief Operations Officer

Howard Bolinger, C.A. – Chief Financial Officer

Glenn Miller – Vice President, Land and 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

Directors

David Antony – Chairman of the Board

Jon P. Clark – Director

Ken Cullen – Director

Ross D.S. Douglas, ICD.D – Director

Sid Dykstra – Director

Tibor Fekete – Director

Byron Lutes – Director, President and Chief Executive Officer

J. Ward Mallabone – Director

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Stock Exchange Listing

STP
Toronto Stock Exchange (TSX)

Transfer Agent

Valiant Trust Company
Calgary, Alberta
Toronto, Ontario

Designed by Bryan Mills Iradesso

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UP

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