

SOUTHERN PACIFIC RESOURCE CORP.

ANNUAL INFORMATION FORM

**FOR THE FINANCIAL YEAR ENDED
JUNE 30, 2009**

OCTOBER 28, 2009

Statements in this Annual Information Form may be viewed as forward-looking statements. Such statements involve risks and uncertainties that could cause actual results to differ materially from those projected. There are no assurances the Corporation can fulfill such forward-looking statements and the Corporation undertakes no obligation to update such statements. Such forward-looking statements are only predictions; actual events or results may differ materially as a result of risks facing the Corporation, some of which are beyond the Corporation's control. The forward-looking statements or information contained in this Annual Information Form are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

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GLOSSARY

Certain terms and abbreviations used in this Annual Information Form are defined below:

“**ABCA**” means the *Business Corporations Act* (Alberta);

“**bitumen**” means a highly viscous oil which is too thick to flow in its natural state, and which cannot be produced without altering its viscosity;

“**Bounty**” means Bounty Developments Ltd.;

“**Common Shares**” means the common shares in the capital of the Corporation;

“**constant prices and costs**” means prices and costs used in an estimate that are:

- (a) the Corporation’s prices and costs as at June 30, 2009, held constant throughout the estimated lives of the properties to which the estimate applies; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a);

“**Corporation**” or “**Southern Pacific**” means Southern Pacific Resource Corp., a corporation pursuant to the ABCA;

“**crude oil**” or “**oil**” means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids;

“**development costs**” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs or support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems;

“**development well**” means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive;

“evaluation oil sands well” means a well drilled in an oil sands area to evaluate the oil sands and is not intended to produce hydrocarbons;

“exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- (b) costs of carrying and retiring unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells;

“forecast prices and costs” means future prices and costs that are:

- (a) generally accepted as being a reasonable outlook of the future; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the reporting issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a);

“future income tax expenses” means future income tax expenses estimated (generally, year-by-year):

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- (b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
- (d) applying to the future pre-tax net cash flows relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated;

“future net revenue” means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs;

“GLJ” means GLJ Petroleum Consultants Ltd., an independent petroleum consulting firm with a head office in Calgary, Alberta;

“gross” means:

- (a) in relation to the Corporation’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
- (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (c) in relation to properties, the total area of properties in which the Corporation has an interest;

“heavy oil” means a dense, viscous oil with a high proportion of bitumen, which is difficult to extract with conventional techniques and is more costly to refine;

“in-situ” means in its original place; in position; in-situ recovery refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection and firefloods;

“June Assets” means the 80% interest in the 76 contiguous sections of oil sands that was sold to the Corporation by Bounty pursuant to the June Asset Acquisition and described as “Long Lake” and “McKay”;

“June Asset Acquisition” means the acquisition of the June Assets from Bounty by Southern Pacific, on the terms and conditions set forth in the June Asset Acquisition Agreement;

“June Asset Acquisition Agreement” means the asset sale agreement dated effective June 15, 2007 between Southern Pacific and Bounty respecting the June Asset Acquisition;

“Leismer Assets” means the 80% interest in the 25 contiguous sections of oil sands leases that was sold by Bounty to the Corporation pursuant to the Leismer Asset Acquisition and described as “Leismer”;

“Leismer Asset Acquisition” means the acquisition of the Leismer Assets from Bounty by Southern Pacific, on the terms and conditions set forth in the Leismer Asset Acquisition Agreement;

“Leismer Asset Acquisition Agreement” means the asset sale agreement dated effective September 15, 2006 between Southern Pacific and Bounty respecting the Leismer Asset Acquisition;

“McDaniel” means McDaniel & Associates Consulting Ltd., an independent petroleum consulting firm with a head office in Calgary, Alberta;

“McDaniel Report” means the report prepared by McDaniel dated August 31, 2009 evaluating the bitumen resources of Southern Pacific, dated effective July 1, 2009;

“net” means:

- (a) in relation to the Corporation’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;
- (b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and
- (c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

“**Net Profit Royalty**” means the royalty payable on net profits which is calculated by subtracting all operating costs and fuel costs from the gross revenue;

“**operating costs**” or “**production costs**” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities;

“**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;

“**probable reserves**” are 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;

“**production**” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas;

“**property acquisition costs**” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

- (a) costs of lease bonuses and options to purchase or lease a property;
- (b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
- (c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties;

“**proved reserves**” are 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;

“**proved property**” means a property or part of a property to which reserves have been specifically attributed;

“**reserves**” are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates being “proved reserves”, “probable reserves” and “possible reserves”;

“**Rochester**” means Rochester Energy Corp.;

“**Rochester Acquisition**” means the acquisition of Rochester pursuant to the plan of arrangement under the ABCA, completed March 4, 2009;

“**SAGD**” means steam assisted gravity drainage, a thermal production method for heavy oil that pairs a high-angle injection well with a nearby production well drilled along a parallel trajectory. Steam is injected into the reservoir through the upper well. As the steam rises and expands, it heats up the heavy oil, reducing its viscosity. Gravity forces the oil to drain into the lower well where it is produced;

“**Saxony**” means Saxony Petroleum Inc.;

“**Saxony Acquisition**” means the acquisition of Saxony pursuant to an amalgamation of Saxony and Southern Pacific Energy completed on April 30, 2009;

“**September Assets**” means the 80% interest in the 81 contiguous sections of oil sands leases that was sold to the Corporation by Bounty pursuant to the September Asset Acquisition and described as “Hangingstone” and “Kirby” areas;

“**September Asset Acquisition**” means the acquisition of the September Assets from Bounty by Southern Pacific, on the terms and conditions set forth in the September Asset Acquisition Agreement;

“**September Asset Acquisition Agreement**” means the asset sale agreement dated effective September 5, 2007 between Southern Pacific and Bounty respecting the September Asset Acquisition;

“**Southern Pacific Energy**” means Southern Pacific Energy Ltd., a corporation pursuant to the ABCA and the wholly-owned subsidiary of the Corporation;

“**Southern Pacific Oil Sands Leases**” means those leases owned by Southern Pacific as set forth herein;

“**TSXV**” means the TSX Venture Exchange Inc.;

“**undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status;

“**unproved property**” means a property or part of a property to which no reserves have been specifically attributed; and

“**well abandonment costs**” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

MONETARY REFERENCES

All monetary references contained in this Annual Information Form are in Canadian dollars unless otherwise specified.

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
BBL	barrel	MCF	thousand cubic feet
BBLs	barrels	MMCF	million cubic feet
MBBLs	thousand barrels	MCF/D	thousand cubic feet per day
MMBBLs	million barrels	MMCF/D	million cubic feet per day
MSTB	1,000 stock tank barrels	MMBTU	million British Thermal Units

BBLs/D	barrels per day	BCF	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids		
STB	standard tank barrels		

Other

API	American Petroleum Institute
API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/D	barrels of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
McfGE	1,000 cubic feet of gas equivalent on the basis of 6 McfGEs to 1 bbl of crude oil. McfGEs may be misleading, particularly if used in isolation. A McfGE conversion ratio of 6 McfGEs to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
McfGE/D	1,000 cubic feet equivalent per day
MmcfGE	1,000 McfGE
Prob	Probable reserves
Poss	Possible reserves
\$000s or M\$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

METRIC CONVERSION TABLE

The following table sets forth certain factors for converting metric measurements into imperial equivalents.

To convert from	To imperial units	Multiply by
Boe	Mcf	6
Mcf	Cubic metres (“m3”)	28.174
Cubic metres	Cubic ft	35.494
Bbls	Cubic metres (“m3”)	0.159
Cubic metres (“m3”)	Bbls	6.290
Feet (“ft”)	Metres	0.305
Metres	Feet (“ft”)	3.281
Miles	Kilometres (“Km”)	1.609
Kilometres (“Km”)	Miles	0.621
Acres	Hectares (“Ha”)	0.405

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form may constitute forward-looking statements. These statements relate to future events or the Corporation'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”, “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 Corporation 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 and such forward-looking statements included in this Annual Information Form should not be unduly relied upon by investors. These statements speak only as of the date of this Annual Information Form and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this Annual Information Form contains forward-looking statements, pertaining to the following:

- projections of market prices and costs;
- supply and demand for oil and natural gas;
- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- treatment under governmental regulatory and taxation regimes; and
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development.

With respect to forward-looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- the Canadian legislative and regulatory environment;
- the impact of increasing competition; and
- the Corporation's ability to obtain additional financing on satisfactory terms.

The Corporation'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 Annual Information Form:

- volatility in the market prices for oil and natural gas;
- uncertainties associated with estimating reserves;
- geological, technical, drilling and processing problems;
- liabilities and risks, including environmental liabilities and risks, inherent in oil and natural gas operations;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; and
- the other factors referred to under "Risk Factors".

The forward-looking statements or information contained in this Annual Information Form are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

NAME AND INCORPORATION

The Corporation was incorporated as “New Wellington Mines Limited” pursuant to the *Companies Act* (British Columbia) on June 20, 1953. On September 30, 1970, Articles of Amendment were filed and the name was changed to “New Wellington Resources Limited”. On March 25, 1976, Articles of Amendment were filed and the name was changed to “International Wellington Resources Ltd.” On November 24, 1983, Articles of Amendment were filed and the name was changed to “Consolidated Wellington Resources Ltd.” On August 28, 1987, Articles of Amendment were filed and the name was changed to “First Hospitality (Canada) Corporation”. On November 5, 1991, Articles of Amendment were filed and the name was changed to “Southern Pacific Development Corp.” The Corporation was transitioned under the *Business Corporations Act* (British Columbia) on April 20, 2005. The Articles of the Corporation were amended by Certificate of Amendment on March 2, 2006 to change the name of the Corporation to “Southern Pacific Resource Corp.”, and further amended by Certificate of Amendment on March 3, 2006 to consolidate the Common Shares on a three for one basis. On November 17, 2006, Articles of Continuance were filed and the Corporation was continued under the ABCA.

Rochester was incorporated as “Rochester Minerals Inc.” under the laws of the Province of British Columbia on October 3, 1983 and was initially engaged in the acquisition and exploration of mineral properties. Rochester subsequently amended its articles to change its name to "Rochester Energy Corp." on April 28, 1997 and changed its name to “International Rochester Energy Corp.” on September 8, 1997. Finally, Rochester was continued into the Province Alberta under the ABCA on March 5, 1999 and changed its name back to Rochester Energy Corp. on July 29, 2004. At the same time, Rochester effected a nine for one share consolidation.

On March 4, 2009, the Corporation completed the Rochester Acquisition and amalgamated with Rochester pursuant to a plan of arrangement under the ABCA. Pursuant to the Rochester Acquisition, Rochester shareholders of record received 0.1977 Common Shares for each common share of Rochester held.

Saxony was incorporated on June 30, 2004 under the ABCA as 1115735 Alberta Ltd., and changed its name to Saxony Petroleum Inc. on July 7, 2004.

On April 30, 2009, the Corporation completed the Saxony Acquisition. As part of the Saxony Acquisition the Corporation’s subsidiary, Southern Pacific Energy, amalgamated with Saxony and Saxony shareholders of record received 0.8302 Common Shares for each common share of Saxony held.

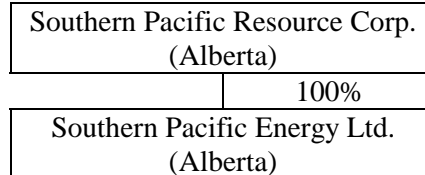
The Corporation is a reporting issuer in the Provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario. The Common Shares are listed on the TSXV under the symbol “**STP**”.

The registered office of Southern Pacific and Southern Pacific Energy is Suite 1000, 250 – 2nd Street, S.W., Calgary, Alberta, T2P 0C1 and the head office is located at Suite 430, 550 - 6th Avenue S.W., Calgary, Alberta, T2P 0S2.

CORPORATE STRUCTURE

Intercorporate Relationships

The Corporation's sole subsidiary is Southern Pacific Energy.



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

Southern Pacific is a resource corporation engaged in the acquisition, exploration and development of oil and natural gas with a focus on oil sands projects in the Western Canadian sedimentary basin. The Corporation does not have any ongoing mining activities or assets from its legacy businesses prior to the March 2006 reorganization of management. The Corporation is headquartered in Calgary, Alberta, Canada. The following describes the development of Southern Pacific's business and major transactions and events of the last three completed financial years, and activities that are expected to occur in the current financial year.

Period From July 1, 2006 to June 30, 2007

On November 22, 2006, the Corporation closed the Leismer Asset Acquisition of the Leismer Assets from Bounty, pursuant to the terms of the Leismer Asset Acquisition Agreement. Bounty and Southern Pacific became joint venture partners in the development of the Leismer Assets. Pursuant to the Leismer Acquisition Agreement, the Corporation paid cash consideration of \$5,752,235 and issued 6,000,000 Common Shares to Bounty and Bounty became a 10% shareholder of the Corporation at this time. In addition, Jon Clark, an employee of Bounty, joined the board of directors of the Corporation as part of the Leismer Asset Acquisition. The Leismer Asset Acquisition included a commitment by Southern Pacific to fund exploration on the Leismer Assets as well as an area of mutual interest in which any bidding at Alberta Crown land sales in the Leismer area would be done jointly with Southern Pacific paying 80% of the costs for an 80% interest. The exploration funding commitments on the Leismer Assets have been satisfied.

The Corporation also issued 400,000 Common Shares to arm's length third parties as a finder's fee in connection with the Leismer Asset Acquisition.

Also on November 22, 2006, in connection with the Leismer Asset Acquisition, the Corporation completed a private placement of 14,000,000 subscription receipts at a price of \$0.50 per subscription receipt for gross proceeds of \$7,000,000. Upon closing of the Leismer Asset Acquisition, the subscription receipts were automatically converted into 14,000,000 units at no additional consideration. Each unit comprised one Common Share and one half of one warrant to acquire one Common Share at an exercise price of \$0.75 per share until November 22, 2007.

On November 22, 2006, the Corporation also completed a private placement of 5,454,545 units at a price of \$0.55 per unit for gross proceeds of \$3,000,000. Each unit comprised one Common Share issued on a “flow-through basis” under the *Income Tax Act* (Canada) and one half of one warrant to acquire one Common Share at \$0.80 per share until November 22, 2007. The proceeds of the private placement were used for payment of the purchase price of the Leismer Asset Acquisition and for the completion of evaluation and development drilling, seismic and for general working capital purposes.

On February 14, 2007, the Corporation completed a private placement of 4,250,000 units at a price of \$1.20 per unit for gross proceeds of \$5,100,000. Each unit comprised one Common Share issued on a “flow-through basis” under the *Income Tax Act* (Canada) and one half of one warrant to acquire a Common Share at \$1.50 per share until February 14, 2008. The proceeds of the private placement were used for the completion of the second stage of evaluation and development drilling of the Leismer Assets.

On June 22, 2007, the Corporation completed a brokered private placement of 11,035,000 units at a price of \$2.90 per unit, for gross proceeds of \$32,001,500. Each unit comprised one Common Share and one half of one warrant to acquire one Common Share at \$4.00 per share until June 22, 2008. The private placement was completed by a syndicate of agents led by Canaccord Capital Corporation, and included Blackmont Capital Inc. and Jones, Gable & Company Limited. The proceeds of the private placement were partially used to complete the June Asset Acquisition of the June Assets, which was completed on June 25, 2007, as described below.

Southern Pacific acquired the interest in the June Assets for total consideration of \$16,000,000 payable to Bounty. The consideration included a cash payment of \$9,600,000 and the issuance of 2,206,897 Common Shares with a deemed value of \$6,400,000. The June Asset Acquisition included a commitment by Southern Pacific to fund a minimum amount of \$22,900,000 on or before April 30, 2009 on an exploration and evaluation program (the “**June Exploration Program**”) in respect of: (a) the June Assets; (b) any area of mutual interest lands; and (c) any lands acquired by the Corporation and Bounty. Pursuant to the June Acquisition Agreement, if the Corporation failed to expend the \$22,900,000 on the June Exploration Program by April 30, 2009, Bounty had an option to purchase one-half of the Corporation’s interest in the June Assets and the area of mutual interest lands for the amount of \$1.00.

As at October 20, 2008, the Corporation satisfied the June Exploration Program as set forth in the June Asset Acquisition Agreement by spending the \$22,900,000 in commitments pursuant to the June Asset Acquisition Agreement. Bounty’s interest in the lands comprised of the June Assets and the area of mutual interest lands was treated as a carried interest until such time as the Corporation spent the \$22,900,000 on the June Exploration Program, after which time Bounty’s 20% interest is considered a non-carried working interest and Bounty is responsible for its share of further expenses incurred for the joint account.

Period From July 1, 2007 to June 30, 2008

On July 11, 2007, the Corporation acquired an 80% interest in 24 sections of land, at a Crown land sale for \$2,289,132. This acreage includes 11 additional contiguous sections of land at South Leismer; this land is located at the south end of the South Leismer property, which follows the oil sands trend on the property. The Corporation paid 80% of the land costs at South Leismer for the 80% interest in the lands in accordance with the June Asset Acquisition Agreement. The Corporation paid 100% of the land costs on the remaining 13 sections of land for the 80% interest. These additional 13 sections of lands were in the Long Lake and McKay areas.

On July 25, 2007, the Corporation acquired an 80% interest in 3 sections of land at a Crown land sale for \$2,841,312. The Corporation paid 100% of the land costs for the 80% interest in accordance with the June Asset Acquisition Agreement.

On August 8, 2007, the Corporation acquired an 80% interest in 8 sections of land at a Crown land sale for \$1,740,666. The Corporation paid 100% of the land costs for the 80% interest in accordance with the June Asset Acquisition Agreement.

On September 5, 2007, the Corporation completed the acquisition of the September Assets for total cash consideration of \$9,500,000 paid to Bounty in accordance with the September Asset Acquisition Agreement. The September Asset Acquisition included a commitment by Southern Pacific to fund a minimum amount of \$20,000,000 on or before April 30, 2009 on an exploration and evaluation program (the “**September Exploration Program**”) in respect of: (a) the September Assets; (b) any area of mutual interest lands comprised of all areas owned jointly with Bounty; or (c) any of the lands or other lands that are owned jointly by Bounty and the Corporation (provided that the ownership ratio is 20% for Bounty and 80% for the Corporation).

The Corporation satisfied the September Exploration Program as set forth in the September Asset Acquisition Agreement by spending the \$16,000,000 in commitments pursuant to the September Asset Acquisition Agreement. Bounty’s interest in the lands comprised of the September Assets and the area of mutual interest lands was treated as a carried interest until such time as the Corporation had spent the said \$20,000,000 on the September Exploration Program after which time Bounty’s 20% interest is considered a non-carried working interest and Bounty is responsible for its share of further expenses incurred for the joint account.

On September 19, 2007, the Corporation acquired an 80% interest in 2 sections of land at a Crown land sale for \$68,034. The Corporation paid 80% of the land costs for the 80% interest in accordance with the agreements with Bounty.

On November 27, 2007, the Corporation completed an underwritten private placement of 27,323,000 Common Shares at a price of \$1.83 per Common Share, and 5,882,000 Common Shares on a flow-through basis at a price of \$2.21 per share, for gross proceeds of \$63,000,310. The private placement was completed by a syndicate of underwriters led by Canaccord Capital Corporation, Orion Securities Inc. and Genuity Capital Markets. The proceeds were used for the completion of evaluation and development drilling on the Corporation’s lands.

Between January and March 2008, the Corporation completed a total of 70 core holes in four of its five core areas.

At McKay, the Corporation drilled a total of 32 core holes on its 59 section block. Two potential project areas were identified during the program and as a result the drilling program was adjusted to focus on this block in order to obtain as much information on the potential projects as possible. In the STP-McKay project area, the Corporation was able to increase the drilling density to four wells per section on some sections. Over the two project areas, STP-McKay and McKay South, the core drilling program encountered gross bitumen zones between 26 and 30 meters thick, and continuous net bitumen zones between 12 and 27 meters thick. The zone porosity ranges from 30% to 35%. In addition, the core holes did not show any evidence of gas or water thief zones that could technically impair SAGD viability. A significant amount of technical data was obtained this winter including 32 full diameter cores over the prospective oilsands horizons, which have been fully analyzed. Downhole formation imaging logs, pressure tests, fluid analyses and warm cap rock cores were also acquired.

At Leismer, a three dimensional seismic program was shot in January over the area that was successfully drilled last year. The data was interpreted and the Corporation drilled another 12 core holes in addition to the 17 core holes drilled in this area successfully during the prior year drilling season. Of the 12 core holes, six were drilled on the three dimensional seismic program and six were drilled on the southern portion of the block based on two dimensional seismic data. Gross bitumen zones of 25 to 42 meters thick were encountered and continuous net bitumen zones of 10 to 18 meters thick were encountered within the three dimensional seismic area. These results, combined with last winter’s drilling results in the same area, have confirmed a potential SAGD project area. Of the six exploration core holes drilled to the south on two dimensional seismic, two solid leads were identified and will be used to plan a future appraisal program in Leismer.

At Long Lake, Southern drilled a total of eight core holes anchored on the 88 km of two dimensional seismic shot last summer and vintage wells in the area. Of these, six of the core holes encountered significant bitumen zones. The gross bitumen zones were between 18 to 38.5 meters thick, and net continuous bitumen zones between 15 to 29.5 meters thick. There are top gas and bottom water issues to deal with on this block; however, Southern Pacific believes it has identified a project area. Further delineation of the project will be planned for in the future.

At Hangingstone, the Corporation drilled a total of 18 core holes this winter on its 64 section block. Using the 175 km of two dimensional seismic shot last summer as a guide to spot the locations on this unexplored block of land, the Corporation found prospective leads in 10 of the 18 core holes. Gross bitumen zones between 10 to 34 meters thick and net continuous bitumen zones between 9 to 15 meters thick were encountered in these 10 wells. This block is still relatively unexplored, and an expanded exploration program for this area is planned for the future, keying off the results of this year's program.

At Kirby, the Corporation shot 87 km of two dimensional seismic at the start of this past winter. This data was then interpreted and several leads were identified and targeted for drilling. However, due to the weather related late start on the rest of the program, it was decided to defer the drilling of this block rather than risk building the winter access roads and not be able to complete the program due to spring break up.

The Corporation completed an analysis and interpretation of all technical data collected during the winter and started a plan for the Corporation to submit a SAGD application for a 12,000 bbl/d project on the McKay block. In order to facilitate this plan, the Corporation engaged a project management team specializing in SAGD project development to work with Southern Pacific's internal staff to coordinate the overall efforts required to prepare the application for the SAGD project. The Corporation engaged three consulting firms to complete the necessary environmental, engineering and logistical efforts required for an a project application. All three firms have been or are currently involved in the planning, design and construction of existing SAGD projects within Alberta.

The Corporation has also engaged a firm to complete its SAGD reservoir modelling which will be used to determine overall SAGD well pattern design and steam requirements by completing a history match on a portion of the existing Suncor SAGD project, which has over five years of production data, and similar reservoir properties to Corporation's STP-McKay project. This history match is an important step to ensure realistic input parameters are used to model Southern Pacific's project.

Period From July 1, 2008 to June 30, 2009

In August 2008, Southern shot and acquired 50 km of ERT (Electrical Resistivity Tomography) data across its McKay and Long Lake leases. This data has been used to further define the prospectivity of these areas and has assisted in the selection of additional test well locations in the STP-McKay project area.

During the winter 2009 exploration program the Corporation drilled 21 stratigraphic test holes within the STP-McKay project area. This brings the total number of delineation wells around the six square mile project area to 43, providing excellent control for exploitable bitumen mapping, and for the orientation of the first proposed phase of SAGD well pairs. The information gathered this past winter has further delineated the extent of its reservoir and has confirmed the viability of the STP-McKay project.

On December 17, 2008, the Corporation reported that it signed a binding arrangement agreement for the Rochester Acquisition and entered into a farmin agreement with Rochester whereby Rochester would expend \$7,000,000 to earn a 3.2% interest in the STP-McKay project lands. This 3.2% interest was subsequently consolidated with the Corporation's interest upon closing the arrangement with Rochester.

On March 4, 2009, the Corporation completed the Rochester Acquisition and amalgamated with Rochester pursuant to a plan of arrangement under the ABCA. Pursuant to the Rochester Acquisition, Rochester shareholders of record received 0.1977 Common Shares for each common share of Rochester held, for a total issuance of 9,998,809 Common Shares.

The Corporation completed an analysis and interpretation of all technical data collected during the 2008/2009 winter, prioritizing its potential project areas and is in the process of preparing a SAGD application for a 12,000 barrels per day (bbls/day) project on the McKay block. In order to facilitate this plan, the Corporation has engaged a team of consultants specializing in SAGD project development to work with our internal staff to coordinate the overall efforts required to prepare an application for the SAGD project.

Over the past winter, the Corporation drilled and successfully tested two water source wells. Based on initial results, these wells will be more than sufficient to provide the water requirements for the SAGD project. Southern Pacific has been working over the past several months in a working group organized by the Canadian Association of Petroleum Producers (CAPP) to comment on the newly proposed Energy Resource and Conservation Board's (ERCB) draft directive: Requirements for Water Measurement, Reporting and Use for Thermal In Situ Oil Sands Schemes. After a thorough review of the draft directive, Southern Pacific is confident STP-McKay will meet or exceed all of the proposed guidelines.

Southern Pacific completed a geo-technical analysis of the plant and pad sites. Earth samples of the plant and well pad sites and surrounding samples were extracted to confirm site integrity and sources of fill material. Preliminary results support the sites selected with only minor modifications.

The Corporation completed additional cap rock integrity analysis. Preliminary analysis of the cap rock program results support sufficient cap rock integrity which will meet all the ERCB requirements for the STP-McKay project.

Concurrent with the field work, Southern Pacific continued to consult directly with aboriginal organizations, public stakeholders and regulatory agencies. Southern Pacific has developed and received approval from Alberta Environment on its Aboriginal Consultation Plan and has also been exempted under the Environment Protection and Enhancement Act (EPEA) from requiring an environmental impact assessment (EIA) report. The consequence of these approvals is that Southern Pacific now has in place a more definitive time-frame around the application process schedule.

On March 18, 2009, the Corporation announced that it entered into a definitive agreement for the Saxony Acquisition.

On April 30, 2009, the Corporation completed the Saxony Acquisition. As part of the Saxony Acquisition the Corporation acquired all of the shares of Saxony and Saxony shareholders of record received 0.8302 Common Shares for each common share of Saxony held, for a total issuance of 14,000,121 Common Shares.

On May 29, 2009, the Corporation submitted an application to the Alberta Energy Resources Conservation Board and Alberta Environment for the development of its in-situ 12,000 bbl/d STP-McKay SAGD project.

Period Subsequent to June 30, 2009

On July 13, 2009, the Corporation announced the completion of an independent reserves evaluation for its STP-McKay project (see "*Statement of Reserves Data and Other Oil and Gas Information*").

On August 24, 2009 the Corporation reported the completion of an independent reserves evaluation for its conventional oil and gas reserves (see "*Statement of Reserves Data and Other Oil and Gas Information*").

On October 9, 2009, the Corporation announced that it signed an agreement with an arm's length public oil and gas corporation to acquire a subsidiary company with producing heavy oil interests that were currently averaging 5,000 barrels per day for a net purchase price of approximately \$90 million (the "**Proposed Acquisition**"). The Proposed Acquisition is expected to close on or about November 2, 2009.

On October 23, 2009, the Corporation completed an underwritten private placement of 104,000,000 subscription receipts ("**Subscription Receipts**") at a price of \$0.50 per Subscription Receipt, to a syndicate of underwriters led by BMO Capital Markets and including Canaccord Capital Corporation, Raymond James Ltd. and Byron Capital Markets, for gross proceeds of \$52,000,000. Each Subscription Receipt represents the right to acquire one Common Share upon exercise, without additional consideration, upon the closing of the Proposed Acquisition. In conjunction with the Proposed Acquisition, BMO Capital Markets conditionally approved a \$45,000,000 credit facility for Southern Pacific. The credit facility will be secured by the Corporation's reserves.

Significant Acquisitions

During the fiscal year ended June 30, 2009, the Corporation completed the Saxony Acquisition and Rochester Acquisition. See "*GENERAL DEVELOPMENT OF THE BUSINESS - Three Year History*". The Corporation has not filed a Form 51-102F4 in relation to these acquisitions.

The Corporation has signed a definitive agreement for the Proposed Acquisition which is expected to close on, or about, November 2, 2009. It is expected that a Form 51-102F4 in relation to the Proposed Acquisition will be filed within 75 days of closing of such acquisition.

DESCRIPTION OF THE BUSINESS OF THE CORPORATION

General

The Corporation is a Calgary, Alberta based oil and gas exploration and development company with all of its exploration and development properties located in the Western Canadian Sedimentary Basin. The primary objective of the Corporation is to explore and develop prospective oil sands properties in Canada, exploit and acquire other complementary heavy oil assets and to produce and develop its conventional assets.

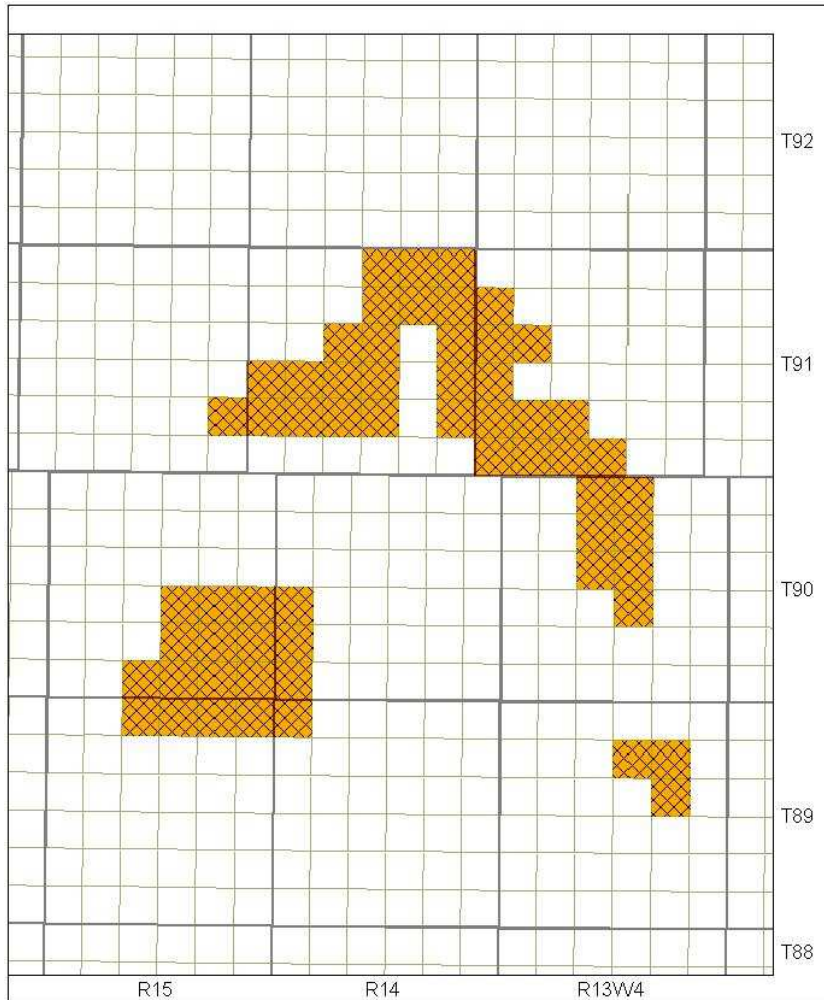
Other Oil and Gas Information

A summary description of the material oil and gas exploration properties of the Corporation, all held by Southern Pacific, as at June 30, 2009 is set out below.

Oil Sands - Property Description and Location

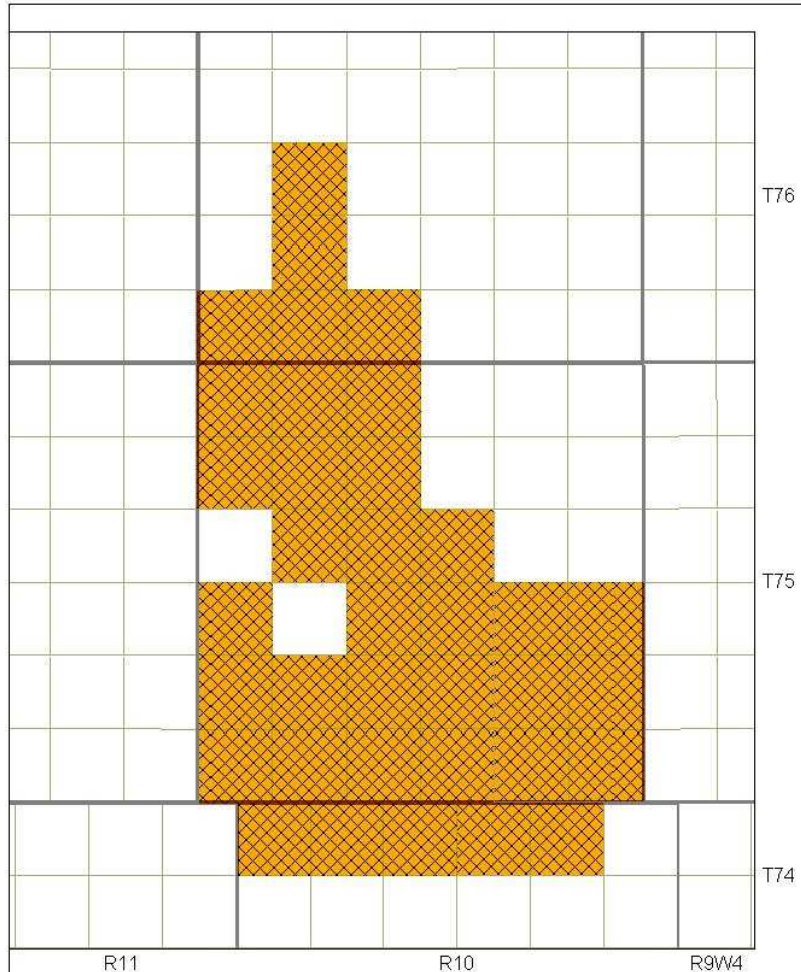
McKay Area

The Corporation's McKay oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 30,208 net acres to the Corporation (37,760 gross acres) at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 59 section parcel, on a gross basis. The Corporation has drilled and abandoned 53 evaluation core holes on the property. Also, 200 km of two dimensional seismic has been shot and evaluated. The Corporation has identified its first SAGD project on the property and has submitted an application for submission to the Energy Resources Conservation Board. The map of the McKay lands is set out below.



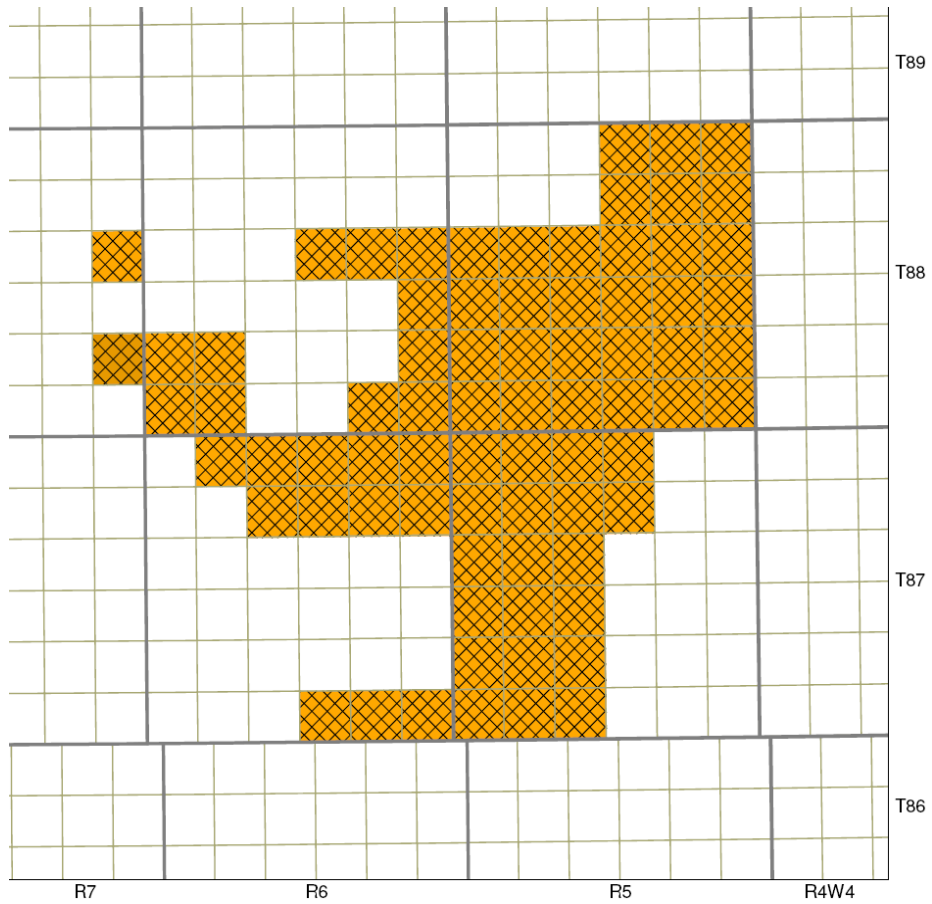
Leismer Area

The Corporation's Leismer oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 18,432 net acres to the Corporation (23,040 gross acres) at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 36 section parcel, on a gross basis. Southern Pacific has drilled and abandoned a total of 29 evaluation core holes on the property. The Corporation has also shot and interpreted 128 km of two dimensional seismic and 20 square kilometres of three dimensional seismic. The map of the Leismer lands is set out below.



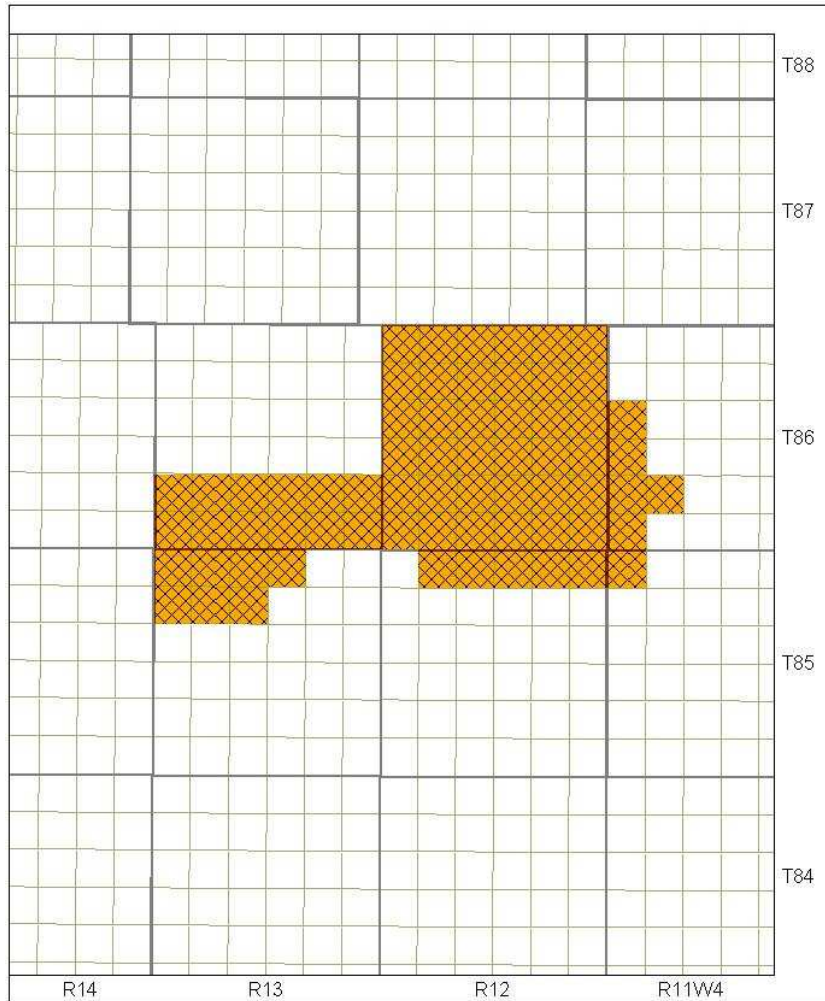
Long Lake Area

The Corporation's Long Lake oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 42,496 net acres to the Corporation (48,000 gross acres) as at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 75 section parcel, on a gross basis. The Corporation has drilled and abandoned 14 evaluation core holes to date on the property. Also, 88 km of two dimensional seismic has been shot and evaluated. The map of the Long Lake lands is set out below:



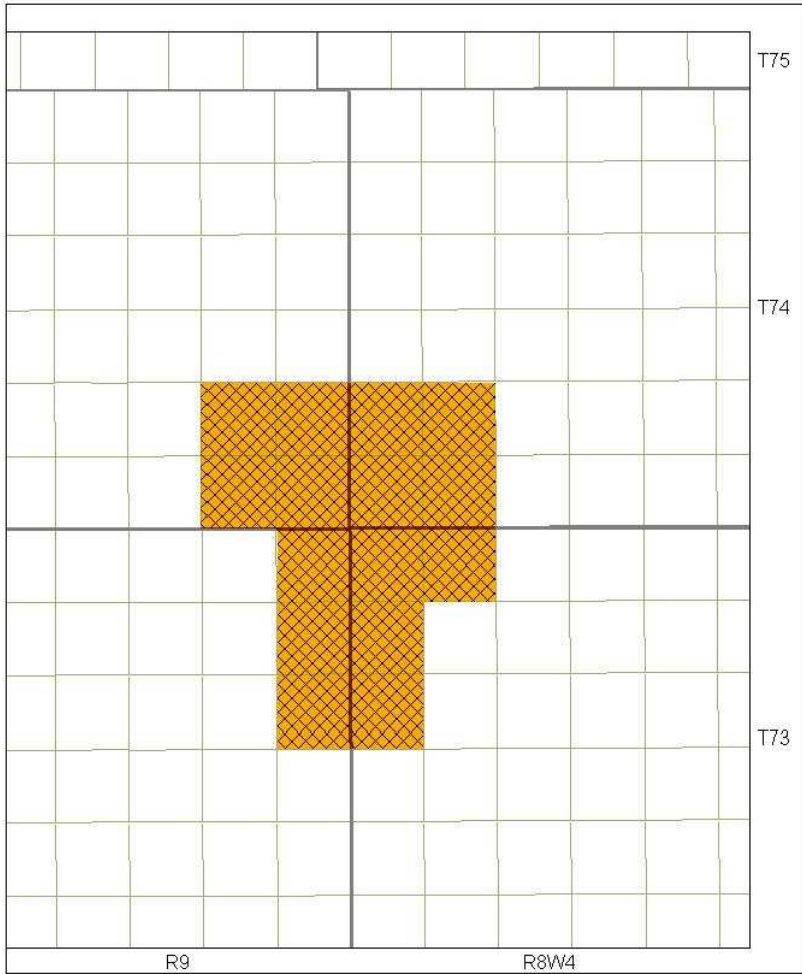
Hangingstone Area

The Corporation's Hangingstone area oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 33,792 net acres to the Corporation (42,240 gross acres) at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 66 section parcel, on a gross basis. The Corporation has drilled and abandoned 18 evaluation core holes on the property. Also, 175 km of two dimensional seismic has been shot and evaluated. The map of the Hangingstone area lands is set out below.



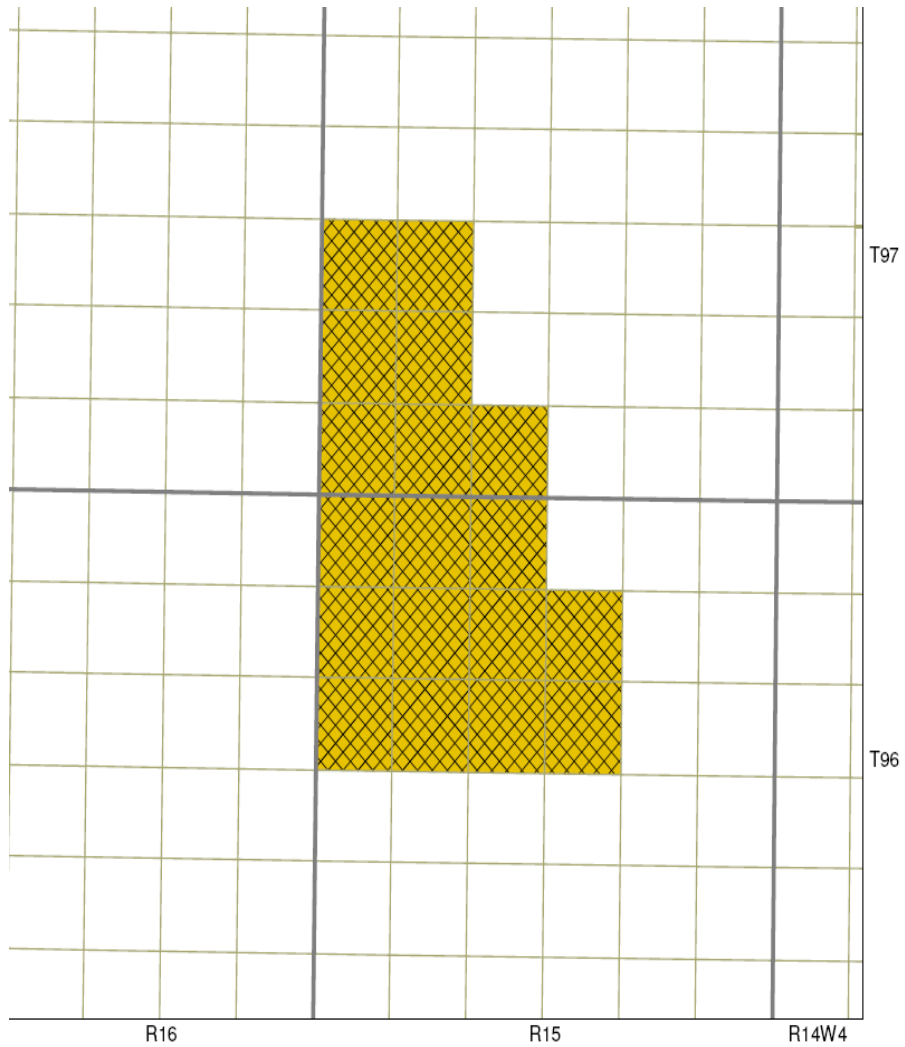
Kirby Area

The Corporation's Kirby oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 7,680 net acres to the Corporation (9,600 gross acres) at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 15 section parcel, on a gross basis. The Corporation has shot and interpreted 87 km of two dimensional seismic on the property. The map of the Kirby lands is set out below.



MacKenzie Area

The Corporation's MacKenzie oil sands leases are located in the McMurray sub-basin in north-eastern Alberta and cover 11,520 net and gross acres to the Corporation at June 30, 2009 and October 28, 2009. The leases consist of crown leases and cover a 18 section parcel, on a gross basis. The map of the MacKenzie lands is set out below.



Conventional Oil and Gas Properties and Wells

Four properties: Brazeau, Sawn Lake, Sutton and Turin, account for the present worth value of the estimated proved producing properties ascribed to the oil and gas reserves as at June 30, 2009. All of these properties are conventional oil and gas assets which were acquired pursuant to the Rochester Acquisition and the Saxony Acquisition.

Brazeau, Alberta

The Brazeau property is located at approximately township 48 range 13 west of the Fifth Meridian, south west of the town of Drayton Valley, Alberta, and accounts for approximately 40% of the Corporation's aggregate production. The Corporation's assets include 100% working interest in one producing gas well and working interests varying from 10% to 50% in three other producing gas wells. There is also one producing oil well in which the Corporation has a 30% working interest. The Corporation's total undeveloped land holdings in this area total 10,298 acres. Oil and gas production from this property is multi zone in nature with the majority coming from the Mannville group. In this area, facilities include tanks, pumps and production equipment associated with the producing wells. The Mannville Formation produces 39 degree API oil to on lease tanks where it is separated from produced water and then trucked to a third party facility for sale. The Mannville Formation sweet gas is produced into a third party gathering system for processing. All hydrocarbon products are taken in kind by the Corporation.

Sawn Lake, Alberta

The Sawn Lake property is located at approximately township 91 range 13 west of the Fifth Meridian, approximately 225 km north of the town of High Prairie, Alberta. The Sawn Lake property is in the exploratory phase and did not account for any of the Corporation's aggregate production for 2008. The Corporation's assets include a 12.5% gross overriding royalty interest with an option to convert into a 25% working interest in 6 sections of land held in the form of a P&NG license. This property was farmed out to an industry partner in 2008 and currently one well has been drilled to validate the license. The partner plans to drill in Q1 2010 to prove the existence of commercial hydrocarbons.

Sutton, Alberta

The Sutton property is located at approximately township 91 range 3 west of the Sixth Meridian, approximately 125 km north west of Fairview, Alberta. The Sutton property accounted for approximately 15% of the Corporation's aggregate production. The Corporation's assets include a 45% working interest in one producing gas well and varying interests from 45% to 75% in three standing gas wells. Gas production from this property is from the Bluesky formation. In this area, facilities include tanks, pumps and production equipment associated with the producing well. The Bluesky Formation produces sweet gas which is gathered and compressed at partner operated facilities. Gas production is taken in kind by the Corporation.

Turin, Alberta

The Turin property is located at approximately township 11 range 18 west of the Fourth Meridian, approximately 75 km north west of Taber, Alberta. The Turin property accounted for approximately 13% of the Corporation's aggregate production. The Corporation's assets include varying working interest from 3.28% to 20% in 32 producing oil wells and five producing gas wells. Oil and gas production from this property is from the Mannville formation. In this area, facilities include tanks, pumps and production equipment associated with the producing wells. The Mannville Formation produces 27 degree API oil which is gathered at a central processing facility in which the Corporation has a five percent working interest. Sweet gas production from the Mannville is also gathered and compressed at this central facility. All hydrocarbon products are taken in kind by the Corporation.

The following table sets out the number of wells associated with the Corporation's conventional assets in which the Corporation held a working interest and which were producing, or considered to be capable of production, as at June 30, 2009.

	Oil		Natural Gas	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
Alberta				
Producing	35	2.5	29	5.2
Non-producing	13	0.9	86	13.0
Saskatchewan				
Producing	0	0	0	0
Non-producing	0	0	2	0.75
British Columbia				
Producing	0	0	0	0
Non-producing	0	0	5	0.4
Total	48	3.4	120	19.35

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

This Statement of Reserves Data and Other Oil and Gas Information is dated June 30, 2009 unless indicated otherwise. The information is presented on a consolidated basis for Southern Pacific.

Disclosure of Reserves Data

Reserves and Future Net Revenue

The following is a summary of the conventional oil and natural gas reserves and the net present values of future net revenue of the Corporation as evaluated by GLJ Petroleum Consultants Ltd. (“**GLJ**”), an independent qualified reserves evaluator appointed by the Corporation pursuant to NI 51-101. All of the Corporation’s conventional oil and gas properties with reserves were independently evaluated by GLJ.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Corporation’s reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ report dated effective June 30, 2009 (the “**GLJ Report**”) will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates attributed to the Corporation’s properties described herein are estimates only. The actual reserves attributed to the Corporation’s properties may be greater or less than those calculated.

The following is a summary of the oil sands reserves and the net present values of future net revenue of the Corporation as evaluated by McDaniel and Associates Consultants Ltd. (“**McDaniel**”), an independent qualified reserves evaluator appointed by the Corporation pursuant to NI 51-101. Only the MacKay property with reserves were independently evaluated by McDaniel. The other oil sands properties of the Corporation were not updated. The Annual Information Form for the year ended June 30, 2008 contains resource estimates for the additional oil sands properties of the Corporation.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Corporation’s reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel report dated effective June 30, 2009 (the “**McDaniel Report**”) will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the McDaniel Report. The recovery and reserves estimates attributed to the Corporation’s properties described herein are estimates only. The actual reserves attributed to the Corporation’s properties may be greater or less than those calculated. Readers should note that totals in the following tables may not add due to rounding.

SUMMARY OF OIL AND GAS WORKING INTEREST RESERVES
forecast prices and costs as of July 1, 2009

RESERVES CATEGORY	RESERVES											
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS		HEAVY OIL		TOTAL OIL EQUIVALENT (CONVENTIONAL)		BITUMEN	
	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)	Gross (mdbl)	Net (mdbl)	Gross (mdbl)	Net (mdbl)	Gross (mdbl)	Net (mdbl)
Oil Sands Business Unit												
Total Proved	-	-	-	-	-	-	-	-	-	-	-	-
Probable Undeveloped	-	-	-	-	-	-	-	-	-	-	54,077	46,636
Total Proved Plus Probable	-	-	-	-	-	-	-	-	-	-	-	-
Possible Undeveloped	-	-	-	-	-	-	-	-	-	-	43,746	34,936
Proved Plus Probable Plus Possible	-	-	-	-	-	-	-	-	-	-	97,823	81,572
Conventional Business Unit												
Proved												
Developed Producing	56	48	1,452	1,302	24	16	0.7	0.7	323	281	-	-
Developed Non-Producing	0	0	239	285	1	1	0	0	41	48	-	-
Undeveloped	0	0	1,012	931	15	11	0	0	184	166	-	-
Total Proved	56	48	2,704	2,518	40	28	0.7	0.7	547	496	-	-
Probable	41	35	2,375	1,999	36	24	0.5	0.5	473	392	-	-
Total Proved Plus Probable	97	83	5,078	4,517	75	52	1.3	1.2	1,020	888	-	-
Combined Oil Sands and Conventional Business Units												
Proved												
Developed Producing	56	48	1,452	1,302	24	16	0.7	0.7	323	281	-	-
Developed Non-Producing	0	0	239	285	1	1	0	0	41	48	-	-
Undeveloped	0	0	1,012	931	15	11	0	0	184	166	-	-
Total Proved	56	48	2,704	2,518	40	28	0.7	0.7	547	496	-	-
Probable	41	35	2,375	1,999	36	24	0.5	0.5	473	392	54,077	46,636
Total Proved Plus Probable	97	83	5,078	4,517	75	52	1.3	1.2	1,020	888	-	-
Possible	-	-	-	-	-	-	-	-	-	-	43,746	34,936
Proved Plus Probable Plus Possible	97	83	5,078	4,517	75	52	1.3	1.2	1,020	888	97,823	81,572

Notes: All gross interests reflect the Corporation's working interest. Table may not add due to rounding.

FORECAST PRICES AND COSTS
NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF JULY 1, 2009

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					FUTURE NET VALUE ⁽¹⁾
	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	10%/year MM(\$/boe)
Oil Sands Business Unit											
Probable Undeveloped	737	319	122	20	(37)	564	233	76	(7)	(54)	2.26
Total Proved Plus Probable	737	319	122	20	(37)	564	233	76	(7)	(54)	2.26
Possible Undeveloped	1,221	398	181	106	72	908	297	138	84	59	4.13
Proved Plus Probable Plus Possible	1,958	717	303	126	35	1,472	530	214	77	5	3.10
Conventional Business Unit											
	CONVENTIONAL VALUES \$M										<i>(M\$/YR (BTAX))</i>
<i>Proved</i>											
Developed Producing	8.4	6.6	5.5	4.7	4.1	8.4	6.6	5.5	4.7	4.1	0.93
Developed Non-Producing	1.4	1.1	1.0	0.8	0.7	1,079	962	857	764	685	0.19
Undeveloped	1.8	0.9	0.3	(0.9)	(0.36)	1,328	580	90	(240)	(468)	0.0
Total Proved	11.6	8.7	6.8	5.4	4.4	10.8	8.2	6.4	5.2	4.2	0.7
Probable	13.3	9.6	7.3	5.9	4.9	10.1	7.2	5.6	4.4	3.7	0.16
Total Proved Plus Probable	24.9	18.3	14.1	11.3	9.3	20.9	15.4	12.0	9.6	8.0	0.94
Combined Oil Sands and Conventional Business Units											
<i>Proved</i>											
Developed Producing	8.4	6.6	5.5	4.7	4.1	8.4	6.6	5.5	4.7	4.1	0.93
Developed Non-Producing	1.3	1.1	1.0	0.8	0.7	1,079	962	857	764	685	0.19
Undeveloped	1.8	0.9	0.3	(0.9)	(0.36)	1,328	580	90	(240)	(468)	0.0
Total Proved	11.6	8.7	6.8	5.4	4.4	10.8	8.2	6.4	5.2	4.2	0.7
Probable	750.3	328.6	129.3	25.9	(32.1)	574.1	240.2	81.6	(2.6)	(50.3)	2.26
Total Proved Plus Probable	761.9	337.3	136.1	31.3	(27.7)	584.9	248.4	88	2.6	(46.1)	3.19
Possible	1,221	398	181	106	72	908	297	138	84	59	4.13
Proved Plus Probable Plus Possible	1,982.9	735.3	317.1	137.3	44.3	1,492.9	545.4	226	86.6	12.9	4.04

Note:

(1) Before deducting future income taxes.

TOTAL FUTURE NET REVENUE

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Oil Sands Business Unit								
Total Proved	-	-	-	-	-	-	-	-
Total Proved Plus Probable	3,760,012	527,848	1,474,377	1,005,408	15,680	736,700	172,806	563,894
Proved Plus Probable Plus Possible	7,870,839	1,314,096	2,806,635	1,758,776	33,389	1,957,944	485,985	1,471,959
Conventional Business Unit								
Proved								
Developed Producing	18,608	2,326	7,524	0	340	8,418	0	8,418
Developed Non-Producing	2,406	185	423	400	45	1,353	274	1,079
Undeveloped	10,497	736	4,255	3,611	91	1,804	476	1,328
Total Proved	31,511	3,248	12,202	4,011	475	11,575	750	10,824
Probable	27,831	3,961	8,601	1,725	209	13,336	3,250	10,086
Total Proved Plus Probable	59,342	7,209	20,803	5,736	684	24,910	4,000	20,910
Combined Oil Sands and Conventional Business Units								
Proved								
Developed Producing	18,608	2,326	7,524	0	340	8,418	0	8,418
Developed Non-Producing	2,406	185	423	400	45	1,353	274	1,079
Undeveloped	10,497	736	4,255	3,611	91	1,804	476	1,328
Total Proved	31,511	3,248	12,202	4,011	475	11,575	750	10,824
Probable	3,787,843	531,809	1,482,978	1,007,133	15,889	750,036	176,056	573,980
Total Proved Plus Probable	3,819,354	537,057	1,695,180	1,011,144	16,364	761,610	176,806	584,804
Possible	4,110,827	786,248	1,332,258	753,368	17,709	1,221,244	313,179	908,065
Proved Plus Probable Plus Possible	7,930,181	1,321,305	2,827,438	1,764,512	34,073	1,982,854	489,985	1,492,869

Notes:

(1) All reserves presented herein represent the Corporation's and the Corporation's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Corporation have been consolidated into the Corporation's accounts.

* Table may not add due to rounding.

**TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
FORECAST PRICES AND COSTS
AS OF JULY 1, 2009**

<i>RESERVES CATEGORY</i>	<i>FUTURE NET REVENUE BEFORE INCOME TAXES (DISCOUNTED 10%)⁽³⁾</i>		
	<i>M\$</i>	<i>\$/boe</i>	<i>\$Mcfe</i>
<i>Light and Medium Oil⁽¹⁾</i>	<i>1,109</i>	<i>26.19</i>	<i>4.37</i>
<i>Heavy Oil⁽¹⁾</i>	<i>26</i>	<i>36.89</i>	<i>6.15</i>
<i>Natural Gas⁽²⁾</i>	<i>4,340</i>	<i>18.20</i>	<i>3.03</i>
<i>Bitumen</i>	<i>-</i>	<i>-</i>	<i>-</i>
<i>Total: Proved Producing</i>	<i>5,475</i>	<i>19.45</i>	<i>3.24</i>
<i>Light and Medium Oil⁽¹⁾</i>	<i>1,109</i>	<i>26.19</i>	<i>4.37</i>
<i>Heavy Oil⁽¹⁾</i>	<i>26</i>	<i>36.89</i>	<i>6.15</i>
<i>Natural Gas⁽²⁾</i>	<i>5,621</i>	<i>12.41</i>	<i>2.07</i>
<i>Bitumen</i>	<i>-</i>	<i>-</i>	<i>-</i>
<i>Total: Total Proved</i>	<i>14,099</i>	<i>13.62</i>	<i>2.27</i>
<i>Light and Medium Oil⁽¹⁾</i>	<i>1,327</i>	<i>24.11</i>	<i>4.02</i>
<i>Heavy Oil⁽¹⁾</i>	<i>41</i>	<i>33.88</i>	<i>5.65</i>
<i>Natural Gas⁽²⁾</i>	<i>12,731</i>	<i>15.30</i>	<i>2.55</i>
<i>Bitumen</i>	<i>122,000</i>	<i>2.62</i>	<i>0.44</i>
<i>Total: Total Proved Plus Probable</i>	<i>128,757</i>	<i>2.74</i>	<i>0.46</i>
<i>Light and Medium Oil⁽¹⁾</i>	<i>1,327</i>	<i>24.11</i>	<i>4.02</i>
<i>Heavy Oil⁽¹⁾</i>	<i>41</i>	<i>33.88</i>	<i>5.65</i>
<i>Natural Gas⁽²⁾</i>	<i>12,731</i>	<i>15.30</i>	<i>2.55</i>
<i>Bitumen</i>	<i>303,000</i>	<i>3.71</i>	<i>0.93</i>
<i>Total: Total Proved Plus Probable and Possible</i>	<i>309,757</i>	<i>3.78</i>	<i>0.63</i>

- Notes:**
- (1) Including solution gas and other by-products.
 - (2) Including by-products but excluding solution gas.
 - (3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Corporation.
 - (4) Processing income included where applicable.
- * Table may not add due to rounding.

**SUMMARY OF PRICING ASSUMPTIONS
AS OF JUNE 30, 2009**

FORECAST PRICES AND COSTS

**MCDANIEL & ASSOCIATES CONSULTANTS LTD.
OIL SANDS PRICE FORECAST**

**Based on McDaniel & Associates Consultants July 1, 2009 Commodity Forecast Pricing
Utilizing historical product and transportation offsets**

Year	U.S./ Canada Exchange	Inflation %/year	WTI Price US\$/Bbl	Edmonton MSW ⁽¹⁾ CDN\$/Bbl	WCS at Hardisty CDN\$/Bbl	WCS at Hardisty % of WTI	Alberta Bow River Hvy at Hardisty ⁽²⁾ CDN\$/Bbl	Alberta Bow River Hvy at Hardisty % of WTI	LLB at Hardisty ⁽³⁾ CDN\$/Bbl	LLB at Hardisty % of WTI	Edmonton C5+ ⁽⁴⁾ CDN\$/Bbl	Diluent at Edmonton ⁽⁴⁾ CDN\$/Bbl	Diluent at Fieldgate CDN\$/Bbl
2009 (6 mos)	0.870	2.0	70.00	79.50	67.40	83.8	69.00	85.8	67.00	83.3	81.50	86.50	88.50
2010	0.880	2.0	74.00	83.10	70.50	83.8	72.10	85.7	70.00	83.2	85.10	91.48	93.52
2011	0.890	2.0	80.60	89.50	73.20	80.8	75.00	82.8	72.80	80.4	91.60	99.40	101.48
2012	0.900	2.0	84.90	93.30	72.50	76.9	74.40	78.9	72.00	76.3	95.40	103.36	105.48
2013	0.950	2.0	92.00	95.80	74.50	76.9	76.40	78.9	74.00	76.4	98.00	106.12	108.28
2014	1.000	2.0	99.40	98.30	76.40	76.9	78.40	78.9	75.90	76.4	100.50	108.78	110.99
2015	1.000	2.0	101.40	100.30	78.00	76.9	80.00	78.9	77.50	76.4	102.60	111.05	113.30
2016	1.000	2.0	103.40	102.30	79.50	76.9	81.60	78.9	79.00	76.4	104.60	113.22	115.51
2017	1.000	2.0	105.40	104.20	81.00	76.9	83.10	78.8	80.50	76.4	106.50	115.29	117.63
2018	1.000	2.0	107.60	106.40	82.70	76.9	84.90	78.9	82.20	76.4	108.80	117.76	120.15
2019	1.000	2.0	109.70	108.50	84.30	76.8	86.50	78.9	83.80	76.4	110.90	120.04	122.48
2020	1.000	2.0	111.90	110.70	86.00	76.9	88.30	78.9	85.50	76.4	113.20	122.53	125.01
2021	1.000	2.0	114.10	112.80	87.70	76.9	90.00	78.9	87.20	76.4	115.30	124.81	127.35
2022	1.000	2.0	116.40	115.10	89.50	76.9	91.80	78.9	88.90	76.4	117.70	127.40	129.99
2023	1.000	2.0	118.80	117.50	91.30	76.9	93.70	78.9	90.80	76.4	120.10	130.00	132.64
2024	1.000	2.0	121.10	119.80	93.10	76.9	95.50	78.9	92.50	76.4	122.50	132.59	135.29
2025	1.000	2.0	123.60	122.20	95.00	76.9	97.50	78.9	94.40	76.4	124.90	135.20	137.94
2026	1.000	2.0	126.00	124.60	96.90	76.9	99.40	78.9	96.20	76.3	127.40	137.90	140.70
2027	1.000	2.0	128.50	127.10	98.80	76.9	101.40	78.9	98.20	76.4	130.00	140.71	143.57
2028	1.000	2.0	131.10	129.60	100.80	76.9	103.40	78.9	100.10	76.4	132.50	143.43	146.34
2029	1.000	2.0	133.70	132.20	102.80	76.9	105.50	78.9	102.10	76.4	135.20	146.34	149.32
2030	1.000	2.0	136.40	134.90	104.90	76.9	107.60	78.9	104.20	76.4	137.90	149.27	152.30
2031	1.000	2.0	139.10	137.60	107.00	76.9	109.70	78.9	106.30	76.4	140.70	152.29	155.39
2032	1.000	2.0	141.90	140.30	109.10	76.9	111.90	78.9	108.40	76.4	143.50	155.33	158.48
2033	1.000	2.0	144.80	143.20	111.30	76.9	114.20	78.9	110.60	76.4	146.40	158.46	161.68
Thereafter	1.000	2.0	+2.0%/yr	+2.0%/yr	+2.0%/yr	76.9	+2.0%/yr	78.9	+2.0%/yr	76.4	+2.0%/yr	+2.0%/yr	+2.0%/yr

**SUMMARY OF PRICING ASSUMPTIONS
AS OF JUNE 30, 2009**

FORECAST PRICES AND COSTS

**MCDANIEL & ASSOCIATES CONSULTANTS LTD.
OIL SANDS PRICE FORECAST**

**Based on McDaniel & Associates Consultants July 1, 2009 Commodity Forecast Pricing
Utilizing historical product and transportation offsets**

Year	SSB/SSP (Synthetic Oil) at Edmonton ⁽⁵⁾⁽⁶⁾ CDNS/Bbl	SSB/SSP at Edmonton % of WTI	Edmonton Prem. SCO ⁽⁷⁾ CDNS/Bbl	Hardisty Delivery		Edmonton Delivery		Natural Gas at AECO CDNS/MMBtu	Natural Gas at Fieldgate CDNS/MMBtu	Alberta Power ⁽⁹⁾ CDNS/WWH
				Diluent at Hardisty CDNS/Bbl	Netback Bitumen at Fieldgate ⁽⁸⁾ CDNS/Bbl	Diluent at Edmonton CDNS/Bbl	Netback Bitumen at Fieldgate ⁽⁸⁾ CDNS/Bbl			
2009 (6 mos)	83.50	103.8	84.20	61.40	55.86	66.90	55.07	4.55	4.35	59.88
	85.10	101.2	85.81	70.50	58.09	69.90	57.16	6.40	6.20	74.30
2010	91.00	100.5	91.73	73.20	58.48	72.60	57.55	7.25	7.05	81.23
2011	94.30	100.0	95.04	72.50	55.71	71.90	54.78	7.75	7.55	85.54
2012	95.80	98.9	96.56	74.50	57.32	73.90	56.38	8.00	7.80	88.00
2013	97.80	98.4	96.58	76.40	58.82	75.80	57.88	8.40	8.20	91.59
2014	99.30	97.9	100.09	78.00	60.06	77.40	59.12	8.75	8.50	94.44
2015	100.80	97.5	101.60	79.50	61.19	78.90	60.26	8.95	8.70	96.55
2016	102.67	97.4	103.49	81.00	62.37	80.40	61.43	9.10	8.85	98.30
2017	104.84	97.4	105.68	82.70	63.66	82.00	62.58	9.30	9.05	100.44
2018	106.91	97.5	107.76	84.30	64.89	83.60	63.80	9.50	9.25	102.59
2019	109.08	97.5	109.95	86.00	66.17	85.30	65.08	9.65	9.40	104.38
2020	111.14	97.4	112.03	87.70	67.54	87.00	66.45	9.85	9.60	106.56
2021	113.41	97.4	114.32	89.50	68.91	88.80	67.82	10.10	9.85	109.13
2022	115.78	97.5	116.70	91.30	70.29	90.60	69.19	10.25	10.00	110.96
2023	118.04	97.5	118.98	93.10	71.66	92.40	70.56	10.50	10.25	113.55
2024	120.41	97.4	121.37	95.00	73.16	94.20	71.92	10.65	10.40	115.41
2025	122.77	97.4	123.75	96.90	74.63	96.10	73.38	10.90	10.60	117.66
2026	125.23	97.5	126.23	98.80	76.04	98.00	74.80	11.15	10.85	120.29
2027	127.70	97.4	128.72	100.80	77.64	100.00	76.39	11.35	11.05	122.57
2028	130.26	97.4	131.30	102.80	79.15	102.00	77.90	11.60	11.30	125.24
2029	132.92	97.4	133.98	104.90	80.80	104.10	79.55	11.80	11.50	127.55
2030	135.58	97.5	136.66	107.00	82.40	106.10	81.00	12.05	11.75	130.25
2031	138.24	97.4	139.34	109.10	83.99	108.20	82.60	12.25	11.95	132.60
2032	141.10	97.4	142.23	111.30	85.69	110.40	84.29	12.55	12.25	135.70
2033	+2.0%/yr	97.4	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

- (1) 40 degree API, 0.5 wt% sulphur
- (2) BRN at Hardisty with density of 929 kg/ml, API of 20.68 and sulphur of 2.85 wt% as per crude assay August 2006, www.crudemonitor.ca
- (3) LLB at Hardisty with density of 926.8 kg/ml, API of 21.04 and sulphur of 3.75 wt% as per crude assay April 2006, www.crudemonitor.ca
- (4) Edmonton C5+ price is based EPL segregated condensate price (725 kg/ml and 0.2 wt% sulphur) and historical average premium to Edmonton MSW. Diluent price has been adjusted for naphtha-quality diluent of 720 kg/m
- (5) SSB at Edmonton with density of 872 kg/ml, API of 30.58' and sulphur of 0.11 wt% as per crude assay August 2006, www.crudemonitor.ca
- (6) SSB production was replaced in Q4 2007 when Syncrude's new aromatics saturation unit came on-line, allowing for the production of SSP
- (7) Prior to 2006/06/30 based on ECA prices quoted for SSB at Edmonton. After 2006/06/30 based on COS realized plantgate price adjusted for transportation to Edmonton
- (8) Based on historical SSB price relationship to WTI with \$0.70/Bbl positive quality adjustment for a premium SCO product.
- (9) Stand ratio of diluent to bitumen assumed to be 0.30 Bbl : 0.70 Bbl based on bitumen assay
- (9) Includes cost of transmission; historical prices based on Alberta Spot Electricity pool price for year plus transmission; Alberta Spot Electricity price forecast is based on estimated marginal cost of natural gas fired generation assuming 7500 Btu is needed to generate 1 kWh and assuming opcosts of 2009\$.01/kwg and return on capital assumed to be 2009\$.1/kWh

GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective July 1, 2009

Year	Inflation %	Bank of Canada Average Noon Exchange Rate \$US/\$Cdn	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma		ICE BRENT Near Month Futures Contract Crude Oil FOB North Sea Then Current \$US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current \$Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current \$Cdn/bbl	Lloyd Blend Crude Oil Stream Quality at Hardisty Then Current \$Cdn/bbl
			Constant 2009 \$ \$US/bbl	Then Current \$US/bbl				
2009 Q1	1.2	0.800	43.00	43.00	45.65	50.17	44.21	42.29
2009 Q2 (e)	0.4	0.860	59.39	59.39	59.30	67.16	61.69	59.88
2009 Q3	2.0	0.870	70.00	70.00	68.50	79.43	69.89	68.31
2009 Q4	2.0	0.870	70.00	70.00	68.50	79.43	69.10	67.51
2009 Full Year	1.4	0.850	60.60	60.60	60.49	69.05	61.22	69.50
2009 Q3-Q4	1.5	0.870	70.00	70.00	68.50	79.43	69.50	67.91
2010	2.0	0.870	70.59	72.00	70.50	81.72	70.28	68.65
2011	2.0	0.880	72.09	75.00	73.50	84.20	70.73	69.47
2012	2.0	0.900	75.39	80.00	78.50	87.89	72.07	70.75
2013	2.0	0.920	78.53	85.00	83.50	91.41	73.13	71.76
2014	2.0	0.950	85.00	93.85	92.35	97.84	78.27	76.81
2015	2.0	0.950	85.00	95.73	94.23	99.82	79.85	78.36
2016	2.0	0.950	85.00	97.64	96.14	101.83	81.47	79.94
2017	2.0	0.950	85.00	99.59	98.09	103.89	83.11	81.55
2018	2.0	0.950	85.00	101.59	100.09	105.99	84.79	83.20
2019+	2.0	0.950	85.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective July 1, 2009

Year	WCS Stream Quality at Hardisty Then Current \$Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current \$Cdn/bbl	Light Crude Oil (35 API, 1.2%S) at Cromer Then Current \$Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current \$Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars)			
					Spec Ethane \$Cdn/bbl	Edmonton Propane \$Cdn/bbl	Edmonton Butane \$Cdn/bbl	Edmonton Pentanes Plus \$Cdn/bbl
2009 Q1	42.57	37.78	47.19	47.32	n/a	43.42	39.15	54.01
2009 Q2 (e)	60.22	56.12	63.53	62.19	N/A	35.03	46.48	69.11
2009 Q3	68.71	63.49	75.45	73.07	12.91	43.68	51.63	81.01
2009 Q4	67.91	62.46	75.45	73.07	17.26	47.66	55.60	81.01
2009 Full Year	59.85	54.96	65.41	63.91	n/a	42.45	48.22	71.29
2009 Q3-Q4	68.31	62.98	75.45	73.07	15.09	45.67	53.62	81.01
2010	69.05	63.24	76.00	73.55	21.22	51.49	63.74	83.36
2011	69.87	63.54	78.31	75.78	24.50	53.05	65.68	85.89
2012	71.15	64.08	81.74	79.10	25.86	55.37	68.55	89.65
2013	72.16	64.31	85.01	81.36	27.15	57.59	71.30	93.24
2014	77.21	68.91	90.99	87.08	28.64	61.64	76.32	99.80
2015	78.76	70.32	92.83	88.84	29.58	62.89	77.86	101.81
2016	80.34	71.76	94.70	90.63	30.23	64.15	79.43	103.87
2017	81.95	73.23	96.62	92.46	30.90	65.45	81.03	105.97
2018	83.60	74.73	98.57	94.33	31.58	66.77	82.67	108.10
2019	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

**GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective July 1, 2009**

Year	AECO/NIT Spot Then Current \$/mmbtu	Alberta Plant Gate				
		Spot Constant 2009 \$/mmbtu	Spot Then Current \$/mmbtu	ARP \$/mmbtu	Aggregator \$/mmbtu	Alliance \$/mmbtu
2009 Q1	5.48	5.25	5.25	5.08	5.50	4.98
2009 Q2 (e)	3.91	3.71	3.71	3.33	3.29	2.87
2009 Q3	3.91	3.71	3.71	3.67	3.54	3.50
2009 Q4	5.17	4.96	4.96	4.90	4.73	4.59
2009 Full Year	4.62	4.41	4.41	4.25	4.27	3.99
2009 Q3-Q4	4.54	4.34	4.34	4.29	4.14	4.05
2010	6.32	5.98	6.10	6.04	5.88	5.60
2011	7.16	6.66	6.93	6.87	6.68	6.46
2012	7.56	6.90	7.32	7.25	7.06	6.84
2013	7.93	7.11	7.70	7.63	7.42	7.21
2014	8.47	7.45	8.23	8.16	7.94	7.74
2015	8.75	7.55	8.50	8.42	8.20	8.00
2016	8.94	7.56	8.69	8.61	8.38	8.18
2017	9.13	7.58	8.88	8.80	8.56	8.36
2018	9.33	7.59	9.07	8.99	8.75	8.55
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2.0%/yr	+2%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate. The plant gate price represents the price before raw gas gathering charges are deducted. AECO - C spot refers to one month price averaged for the year.

Properties With No Attributed Reserves

As at June 30, 2009, the Corporation had 165,440 gross and 138,752 net acres of oil sands properties in Alberta in which the Corporation has an interest, but no reserves have been assigned. Contingent resources have been assigned to the properties, but further development drilling is required to convert the resources to reserves. The Corporation has no oil sands properties in which its rights to explore, develop and exploit will, absent further action, will expire within one year.

As at June 30, 2009, the Corporation had 13,034 gross and 5,517 net acres of conventional properties that will expire within one year without any action by the Corporation and which do not have any reserves assigned to them.

Forward Contracts

The Corporation has no production or forward contracts in place as at June 30, 2009. On September 24, 2009, the Corporation put a natural gas costless collar in place effective for the period from November 1, 2009 to April 30, 2009. The collar had a floor price of \$4.00 and ceiling price of \$5.85 on a volume of 400 gj per day.

Additional Information Concerning Abandonment And Reclamation Costs

The Corporation has abandoned all of its evaluation oil sands wells (core holes) drilled to date. There may be some additional work over the next few winters to fully reclaim the sites but it is not considered significant. In the future, as the Corporation develops its projects, producing well abandonment costs and plant site abandonment costs will be factored into the reserve evaluations reports to reflect overall net revenue and project value.

The Corporation is required to provide for future removal and restoration costs on its conventional oil and gas assets. Southern Pacific estimated these costs in accordance with the 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, discounted to its present value using the Corporation'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 the passage of time and 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.

Tax Horizon

The Corporation was not required to pay income taxes during the year ended June 30, 2009. The Corporation estimates that it will not be required to pay income taxes until after 2012.

Costs Incurred

The following table shows (in thousands of dollars) the Corporation's costs for the categories for the year ended June 30, 2009:

	<u>June 30, 2009</u>
	(\$)
Property Acquisition Costs - Proved Properties	6,872,790
Exploration Costs	<u>10,468,932</u>
Total	<u>17,341,722</u>

Exploration and Development Activities

The Corporation did not drill any conventional wells in the year ended June 30, 2009.

The Corporation has drilled a total of 91 gross evaluation oil sands wells (core holes) (72.8 net) on its leases to evaluate for bitumen presence in the past two fiscal years. All of these wells have been fully reclaimed.

Reserves Reconciliation

A reconciliation of changes to the Corporation's net probable and net proved plus probable reserves is provided in the table below. This reconciliation reflects changes to the Corporation's reserves estimated using forecast prices and costs.

Reconciliation of Corporation Net Reserves by Principal Product Type

Forecast Prices and Costs

FACTORS	LIGHT AND MEDIUM OIL			NATURAL GAS			NATURAL GAS LIQUIDS		
	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
June 30, 2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	57	41	98	2,766	2,375	5,141	41	36	77
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	(1.1)	0.0	(1.1)	(63)	0.0	(63)	(1.2)	0.0	(1.2)
June 30, 2009	56	41	97	2,704	2,375	5,078	40	36	76

Reconciliation of Corporation Net Reserves by Principal Product Type

Forecast Prices and Costs

FACTORS	HEAVY OIL			BITUMEN		
	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
June 30, 2008	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	0.0	0.0	0.0	0.0	54,100	97,800
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	1.0	1.0	1.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	(0.1)	0.0	(0.1)	0.0	0.0	0.0
June 30, 2009	1.0	1.0	1.0	0.0	54,100	97,800

Production Estimates

The following table discloses for each product type the total proved plus probable forecasted volume of production estimated by GLJ for 2010 in the estimates of future net revenue from proved reserves disclosed above under the heading “*Statement of Reserves Data and Other Oil and Gas Information*”.

	2010 Calendar Year - Forecast Prices & Costs Gross Daily Production ⁽²⁾
Reserves Category	
Light & Medium Oil (bbls/d)	13
Heavy Oil (bbls/d)	Nil
Associated and Non-Associated Gas (Mcf/d)	873
Natural Gas Liquids (bbls/d)	14
Total ⁽¹⁾ (boe/d)	173

Notes:

- (1) Barrels of Oil Equivalent (boe) have been reported based on natural gas conversion of 6 Mcf/1 bbl.
(2) Gross production is the Corporation’s interest before all royalty deductions.

Production History

The following table discloses, on a quarterly basis for the year ended June 30, 2009, the Corporation’s share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

	Three Months Ended				
	September 30, 2008	December 31, 2008	March 31, 2009	June 30, 2009	Average
Average Daily Production					
Light and Medium Oil (Bbl/d)	Nil	Nil	0	12	3
Natural gas (Mcf/d)	Nil	Nil	45	750	198
NGL (Bbl/d)	Nil	Nil	3	13	4
Total (BOE/d)	Nil	Nil	11	150	40
Average Price Received (\$)					
Light and Medium Oil (Bbl/d)	Nil	Nil	0	64.38	56.31
Natural gas (Mcf/d)	Nil	Nil	4.93	3.37	3.50
NGL (Bbl/d)	Nil	Nil	30.37	57.56	52.56
Total (BOE/d)	Nil	Nil	23.85	26.99	26.78
Combined Netback (\$)					
Revenue	Nil	Nil	23.85	26.99	26.78
Royalties	Nil	Nil	(8.95)	2.75	1.99
Transportation	Nil	Nil	0	(1.23)	(1.15)
Operating Costs	Nil	Nil	(13.68)	(14.97)	(14.88)
Netback	Nil	Nil	1.22	13.54	12.74

Production Volume by Field

The following table discloses for each **important field**, and in total, the Corporation's production volumes for the financial year ended June 30, 2009 for each product type.

Field	Light and Medium Crude Oil (Bbls)	Natural Gas (Mcf)	Natural Gas Liquids (Bbls)	BOE (BOE)	%
Brazeau	365	26,222	1,147	5,882	40
Sutton	0	14,370	0	2,395	16
Turin	684	2,622	0	1,121	8
Other	46	29,054	313	5,201	36
Total	1,094	72,269	1,460	14,598	100

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved 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	229,562	171,749	5,517
Saskatchewan	1,122	809	0
British Columbia	1,937	145	0
Total	232,621	172,703	5,517

Employees/Consultants

The Corporation's staffing levels, as at October 28, 2009, was six (6) full-time employees and five (5) part-time consultants located in Calgary, Alberta. Upon completion of the Proposed Acquisition, an additional 21 full time equivalent are expected to be employed by the Corporation. The level of staffing will vary based on future operational and administrative demands.

Environmental

The Corporation believes that it is in compliance with applicable existing environmental laws and regulations and is not aware of any proposed environmental legislation or regulations with which it would not be in material compliance. However, the natural resources industry may in the future become subject to more stringent environmental protection rules. This could increase the cost of doing business and may have a negative impact on earnings in the future.

Reorganizations

In March 2006, the Corporation underwent a change of management. Former management approached members of current management to replace them and seek other opportunities and types of projects for the Corporation. At this time, the head office was moved to Calgary, Alberta and individuals with oil and gas experience were added to the board and management of the Corporation.

The Leismer Asset Acquisition, which was completed on November 22, 2006, as described above, constituted a reverse take-over pursuant to the policies of the TSXV. See "*GENERAL DEVELOPMENT OF THE BUSINESS - Three Year History*".

RISK FACTORS

Overview

The Corporation's business consists of the exploration and development of oil and gas properties in Alberta. There are a number of inherent risks associated with the exploration, development and production of oil and gas reserves. Many of these risks are beyond the control of the Corporation.

The Corporation

There are numerous factors which may affect the success of the Corporation's business which are beyond the Corporation's control including local, national and international economic and political conditions. The Corporation's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The Corporation has a limited history of operations and earnings and there can be no assurance that the Corporation's business will be successful or profitable or that commercial quantities of oil and natural gas will be discovered by the Corporation.

Additional Financing and Expenditures Required

Depending on future exploration, development, acquisition and divestiture plans, the Corporation will require additional financing. The ability of the Corporation to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Corporation. There can be no assurance that the Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation. If additional financing is raised by the issuance of shares from treasury of the Corporation, control of the Corporation may change and shareholders may suffer additional dilution.

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may temporarily increase the Corporation's debt levels above industry standards.

Industry Conditions

The oil and gas industry is intensely competitive and the Corporation competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas but, also carry on refining operations and market petroleum and other products on an international basis. Bitumen, oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations.

The marketability and price of bitumen, oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond the control of the Corporation. The ability of the Corporation to market any hydrocarbons discovered may depend upon its ability to acquire space on pipelines which deliver such products to commercial markets. The Corporation is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its probable and possible reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Corporation is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and gas industry in Canada, including the oil sands industry, operates under federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of bitumen, crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the bitumen, crude oil and natural gas industry could reduce demand for bitumen, crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which the Corporation may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Stage of Development of Southern Pacific

The Corporation anticipates drilling wells to further delineate reserves on the Corporation's lands. Any development of the resources or reserves will be subject to the Energy Resources Conservation Board and Alberta Environment approval and review prior to the necessary approvals required to produce bitumen using a SAGD process being obtained. The regulatory approval process can involve stakeholder consultation, including other mineral rights holders in the area (such as holders of traditional petroleum and natural gas rights), environmental impact assessments and public hearings, among other things. There can be no assurance that the required approvals will be obtained and, if obtained, will be obtained on terms and conditions acceptable to Southern Pacific. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment or restructuring of the affected projects and increased costs, all of which could have a material adverse affect on Southern Pacific.

If all regulatory approvals are obtained, there is a risk that design and construction of the facilities and infrastructure to support the projects will not be completed on time, on budget or at all. Additionally, there is a risk that the Corporation's projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- breakdown or failure of equipment or processes;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- delays induced by weather;
- disruption or delays in availability of transportation services;
- errors in construction;
- changes in scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents;
- permit requirement violation;
- reservoir performance;
- energy supply disruption;
- shortages of or delays in accessing drilling rigs and services; and
- catastrophic events such as fires, storms or explosions.

The industry is entering a period where unprecedented oil sands development and industrial activity is planned at a time when activity in many other sectors is also high. If the Corporation's projects advance to the development stage, Southern Pacific will need to compete for equipment, supplies, services, and labour in this environment which could result in increased costs, shortages of goods and services that delay progress, or both. Increased competition for equipment, materials and labour may result in increased costs that could have a material adverse effect on Southern Pacific's business, financial condition or results of operations.

Operating Costs

The operating costs of the Corporation's projects, which have the potential to vary considerably, are significant components of the cost of production of the petroleum products produced by the Corporation's projects. The operating costs of the Corporation's projects may vary considerably during the operating period. The factors which could affect operating costs include, without limitation:

- the amount and cost of labour to operate the Corporation's projects;
- the cost of catalyst and chemicals;
- the actual steam oil ratio required to operate the SAGD well pairs;
- the cost of natural gas and electricity;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost to transport sales products and the cost to dispose of certain by-products;
- the cost of insurance; and
- the cost to purchase and transport diluents to blend with the produced bitumen.

Southern Pacific's earnings may be reduced if increases in operating costs are incurred.

Infrastructure for the Corporation's Projects

Southern Pacific will depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for the Corporation's projects. Southern Pacific also anticipates that it will rely on certain infrastructure owned and operated or to be constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to Southern Pacific. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required to complete the Corporation's projects on a timely basis and on acceptable commercial terms will negatively impact Southern Pacific's operation and financial results.

In-situ Extraction

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology is relatively new and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of SAGD operations.

Recovery of Bitumen

Recovering bitumen from oil sands involves particular risks and uncertainties. The Corporation's project are susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due

to the interdependence of its component systems. Severe weather conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to Southern Pacific's facilities or wells and liability to third parties against which Southern Pacific may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

Pricing of Bitumen

There is no generally recognized approach to determine the constant price for bitumen because the bitumen market is not yet mature and there are no published reference prices for bitumen. To price bitumen, marketers apply formulas that take as a reference point the prices published for crude oil of particular qualities such as Edmonton light, Lloydminster blend, or the more internationally known West Texas Intermediate.

The price of bitumen fluctuates widely during the course of a year, with the lowest prices typically occurring at the end of the calendar year because of decreased seasonal demand for asphalt and other bitumen-derived products coupled with higher prices for diluents added to facilitate pipeline transportation of bitumen.

Operational Hazards

The operation of the Corporation's projects and the other oil and gas properties of the Corporation will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The project could be interrupted by natural disasters or other events beyond the control of the Corporation. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on the Corporation's business, financial condition and results of operations.

Abandonment and Reclamation Costs

Southern Pacific will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of the Corporation's projects and reclamation of its lands at the end of its economic life, which abandonment and reclamation costs may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In addition, in the future Southern Pacific may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Terrorist Attacks and the Threat of Terrorist Attacks

The long-term impact of terrorist attacks in the United States, such as the attacks on September 11, 2001, and in Canada and the threat of future terrorist attacks on the energy transportation industry in general, and on Southern Pacific in particular, is not known at this time. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks will result in increased costs to Southern Pacific's business.

Access to Human Resources

The labour force in the Fort McMurray and surrounding area is limited and the inability to access the necessary skilled labourers to construct and operate Southern Pacific's projects could have an adverse affect on Southern Pacific's development plans. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs associated with the development of the Corporation's projects.

Competition

The Corporation's projects compete with other explorers of bitumen and conventional explorers of oil and gas. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than Southern Pacific have announced plans to enter the oil sands business, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Royalty Regime

In the event that the Corporation's projects are developed and become operational, Southern Pacific's revenue and expenses will be directly affected by the royalty regime applicable to the Corporation. The economic benefit of future capital expenditures on the Corporation's projects is, in many cases, dependent on a satisfactory royalty regime.

There can be no assurance that the federal government and the Province of Alberta will not adopt a new royalty regime which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged.

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "NRF") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches \$120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

Oil sands projects are now subject to the NRF, and regulated, among others, by the Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation and the Bitumen Valuation Methodology

(Ministerial) Regulation, 2009, all approved by the Government of Alberta on December 10, 2008. The rates applicable to oil sands are between 1% and 9% and are calculated depending on the price of oil. The royalty payable is 1% when oil is priced below or at \$55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at \$120 or higher. The after payout net royalty starts at 25% and increases for every dollar when oil is priced above \$55 up to 40% when oil is priced at \$120 or higher.

Environmental Regulation and Risks

Extensive environmental laws and regulations will affect all of the operations of the Corporation. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that the Corporation will not incur substantial financial obligations in connection with environmental compliance.

The construction, operation and decommissioning of the Corporation's projects and reclamation of the project's land are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued renewed, or that they will not contain terms and conditions which make the project uneconomic or cause the Corporation to significantly alter the project. Significant liability could be imposed on the Corporation for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased by the Corporation or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on the Corporation. Moreover, the Corporation cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Corporation for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Corporation.

Kyoto Accord

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas production. Future federal legislation, together with existing provincial emission reduction legislation, such as in Alberta's *Climate Change and Emissions Management Act*, may require the reduction of emissions and/or emissions intensity from the Corporation's oil and gas exploration and development activities. The direct or indirect costs of such legislation may adversely affect the Corporation's operations. No assurance can be given that future environmental approvals, laws or regulations will not adversely impact (i) the ability of the Corporation to conduct its operations or (ii) the Corporation's production or (iii) the Corporation's unit costs of production. Equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, such as the Corporation. Mitigation of the risk of future legislative or regulatory limits on the emission of greenhouse gases may include the acquisition of emission reduction or off-set credits from third parties. However, emission reduction or off-set credits may not be available for acquisition by the Corporation or may not be available on an economic basis and may not be recognized or

qualify under future legislative or regulatory regimes as mitigation for the emission of greenhouse gases by the Corporation.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial condition, operating results and future growth are dependent on the prevailing prices for its oil and natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of the Corporation. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on the Corporation and the level of its oil and natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by the Corporation. No assurance can be given that oil and natural gas prices will be sustained at levels which will enable the Corporation to operate profitably. From time to time the Corporation may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and resources and cash flows to be derived therefrom, including many factors beyond the control of the Corporation. The reserves, resources and estimated future net cash flow from the Corporation's properties have been independently evaluated by McDaniel with an effective date of July 1, 2009 and GLJ with an effective date of June 30, 2009. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands resources may impair the profitability of the Corporation's projects in any particular period. The present value of estimated future net cash flows referred to herein should not be construed as the current market value of estimated oil and natural gas reserves attributable to the Corporation's properties. The estimated discounted future cash flow from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net cash flows will also be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas properties or the commencement of drilling wells, such reviews do not guarantee or certify that an

unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation.

Potential Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. Some of the directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Exchange Rate Risk

Revenue received from the sale of crude oil is generally referenced to a price denominated in US\$. As the Corporation reports its operating results in CDN\$, fluctuations in product pricing and fluctuations in the rate of exchange between the US\$ and CDN\$ would affect reported revenues and reported results.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Corporation's projects and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Corporation's projects.

DIVIDENDS

The Corporation has not declared or paid any dividends in the three most recently completed financial years. Any decision to pay dividends on the Common Shares will be made by the board of directors of the Corporation on the basis of the Corporation's earnings, financial requirements and other conditions existing at the relevant time.

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares ("**Preferred Shares**"), issuable in series. As of October 28, 2009, an aggregate of 121,621,307 Common Shares and no preferred shares were issued and outstanding. As of October 28, 2009, an aggregate of 104,000,000 Subscription Receipts which convert into Common Shares upon completion of the Proposed Acquisition were issued and outstanding.

The holders of the Common Shares are entitled to receive notice of and attend any meeting of the Corporation's shareholders and are entitled to one vote for each Common Share held (except at meetings where only the holders of another class of shares are entitled to vote). Subject to the rights attached to any other class of shares, the holders of the Common Shares are entitled to receive dividends, if, as and when

declared by the board of directors of the Corporation and are entitled to receive the remaining property upon liquidation of the Corporation.

The Corporation is authorized to issue an unlimited number of Preferred Shares. The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the board of directors of the Corporation, who may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. As at the date hereof, there are no Preferred Shares issued and outstanding. The Preferred Shares of each series shall, with respect to dividends, liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding up its affairs, shall be entitled to preference over the Common Shares and the shares of any other class ranking junior to the Preferred Shares. The Preferred Shares of any series may also be given such other preferences and priorities over the Common Shares and any other shares of the Corporation ranking junior to such series of Preferred Shares.

MARKET FOR SECURITIES

The following table sets forth the monthly high and low closing prices and volumes of the trading of the Common Shares for the periods indicated. The Common Shares trade under the symbol “STP” on the TSXV.

	Price Range		Trading Volume
	High	Low	
2008			
July	\$0.74	\$0.57	2,196,800
August	\$0.66	\$0.45	1,900,900
September	\$0.51	\$0.25	5,240,400
October	\$0.345	\$0.12	5,349,800
November	\$0.195	\$0.095	5,033,200
December	\$0.125	\$0.075	17,154,700
2009			
January	\$0.14	\$0.105	5,094,900
February	\$0.26	\$0.10	7,704,800
March	\$0.19	\$0.135	3,546,900
April	\$0.285	\$0.15	5,904,200
May	\$0.60	\$0.28	13,504,800
June	\$0.71	\$0.335	8,947,000
July	\$0.475	\$0.30	3,941,900
August	\$0.42	\$0.28	4,675,800
September	\$0.65	\$0.37	5,565,100
October ⁽¹⁾	\$0.60	\$0.54	8,370,532

Note:

(1) Up to October 27, 2009.

PRIOR SALES

Other than options to acquire Common Shares pursuant to the Corporation’s option plan, during the financial year ended June 30, 2009 the Corporation issued an aggregate of 3,444,164 warrants to purchase Common Shares and 255,182 brokers options to acquire Common Shares as follows:

Description	Date	Number of Warrants/ Broker Options	Issue or Exercise Price Per Common Share
Warrants	March 3, 2009	3,444,164	See Notes 1 and 2
Broker Warrants	March 3, 2009	255,182	See Notes 1 and 3

Notes:

- (1) All of these securities were issued pursuant to the Rochester Acquisition.
- (2) A total of 3,444,164 of these Warrants remained outstanding as at June 30, 2009 and had exercise prices and expiry dates as follows:
 - (a) 835,364 Warrants were exercisable at a price of \$5.06 and expired on July 17, 2009;
 - (b) 481,993 Warrants are exercisable at a price of \$2.02 and expire on October 29, 2009;
 - (c) 242,677 Warrants are exercisable at a price of \$2.02 and expire on July 18, 2010;
 - (d) 128,505 Warrants are exercisable at a price of \$2.02 and expire on September 26, 2010;
 - (e) 1,566,278 Warrants are exercisable at a price of \$2.02 and expire on March 23, 2011; and
 - (e) 189,347 Warrants are exercisable at a price of \$1.01 and expire on March 13, 2012.
- (3) A total of 255,182 of these Broker Options remained outstanding as at June 30, 2009 and had exercise prices and expiry dates as follows:
 - (a) 29,147 Broker Options were exercisable at a price of \$3.79 and expired on July 17, 2009;
 - (b) 131,259 Broker Options were exercisable at a price of \$3.79 and expired on September 14, 2009;
 - (c) 65,629 Broker Options were exercisable at a price of \$5.06 and expired on September 14, 2009; and
 - (d) 29,147 Broker Options were exercisable at a price of \$3.79 and expired on September 17, 2009.

ESCROWED SECURITIES

The number of Common Shares held in escrow and the percentage that number represents of the outstanding securities of the Corporation as of June 30, 2009 is as follows:

Designation of Class	Number of Securities Held in Escrow	Percentage of Class⁽¹⁾
Common Shares	952,500 ⁽²⁾	0.07%
Common Shares	516,173 ⁽³⁾	0.04%
Warrants	2,675,736 ⁽³⁾	62.7%

Notes:

- (1) As of June 30, 2009, there were 121,611,307 Common Shares outstanding.
- (2) These escrowed Common Shares are escrowed pursuant to an escrow agreement dated November 22, 2006 among the Corporation, Valiant Trust Company and certain shareholders of the Corporation (the “**Escrowed Shares**”). The original escrow agent appointed pursuant to the escrow agreement was Computershare Trust Company of Canada, who has been replaced by Valiant Trust Company as the current escrow agent. The Escrowed Shares were releasable as to 10% on December 11, 2006, the date of Final Exchange Bulletin of the TSXV for the Leismer Asset Acquisition, and as to 15% on each of the 6, 12, 18, 24, 30 and 36 month anniversaries of December 11, 2006.
- (3) These escrowed Common Shares and Warrants are escrowed pursuant to an escrow agreement dated September 12, 2007 among the Corporation, Valiant Trust Company and certain shareholders of the Corporation (the “**Escrowed Securities**”). The Escrowed Securities were releasable as to 10% on September 12, 2007, and as to 15% on each of the 6, 12, 18, 24, 30 and 36 month anniversaries of September 12, 2007.

DIRECTORS AND OFFICERS

The following table sets forth the names and municipalities of residence of the current directors and executive officers of the Corporation, their respective positions and offices with the Corporation and date first appointed or elected as a director and/or officer and their principal occupation(s) within the past five years.

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Byron Lutes, P. Eng ⁽³⁾ Calgary, Alberta	Chief Executive Officer, President and Director	Mr. Lutes is Chief Executive Officer and President of the Corporation. Mr. Lutes is a Professional Engineer with over 23 years of experience in the oil and gas sector including 12 years in senior officer roles. Prior to joining Southern Pacific, Mr Lutes was the Vice President, Operations at Mancal Energy Inc. Previous to that appointment, Mr Lutes was the Vice President, Engineering at Hunt Oil Company of Canada and Newport Petroleum Corporation.	January 7, 2008 (Officer) April 29, 2009 (Director and CEO)
David M. Antony, CA ⁽¹⁾ Calgary, Alberta	Chairman and Director	Mr. Antony is a Chartered Accountant and is currently the Chairman of the board of the Corporation. Mr. Antony has over 15 years experience in assisting companies in structuring transactions, accessing capital, and corporate governance. In the last five years, Mr. Antony has been Chief Executive Officer of Southern Pacific Resource Corp. (from 2006 to May 2009). Prior thereto, Mr. Antony was a partner at an accounting firm. He is currently Chief Executive Officer of Blackhawk Resource Corp. (since February, 2009) and March Resources Corp. (since 1999).	March 9, 2006
Jon P. Clark, M.Sc. Geo., ⁽²⁾⁽³⁾ Calgary, Alberta	Director	Mr. Clark has been the Exploration Manager for Bounty, a private oil and gas exploration company, since 1996. Mr. Clark is also an employee of Bounty and Nutcracker Holdings Ltd.	November 17, 2006
Tibor Fekete, P.Eng ⁽¹⁾⁽²⁾⁽³⁾ Calgary, Alberta	Director	Mr. Fekete is the President of Synerg Resources Ltd. and is a professional engineer with over 45 years experience in the oil and gas industry. Mr. Fekete founded and operated T.Fekete and Associates Inc., a leading reservoir engineering firm.	March 9, 2006
J. Ward Mallabone, LLB ⁽¹⁾⁽²⁾ Calgary, Alberta	Director	Mr. Mallabone is currently the President and Chief Executive Officer of Priviti Capital Corporation a private equity fund. Prior thereto he was the Chief Operating Officer of the Enervest Group of companies, which included Enervest Diversified Income Trust (EIT.UN – TSX) the largest publicly traded closed-end fund in Canada.	November 17, 2006
Howard Bolinger, CA Calgary, Alberta	Chief Financial Officer	Mr. Bolinger is the Chief Financial Officer of the Corporation. Mr. Bolinger is a Chartered Accountant and he has over 12 years of experience in corporate finance. He was the Chief Financial Officer of Proventure Income Fund, a public income trust listed on the TSXV from its inception in December 2005 until May 2006. He was also the Chief Financial Officer of Cervus LP, a public limited partnership listed on the TSXV from its inception in April 2003 until March 2006. Prior to that he was Chief Financial Officer of Cervus Corporation, a public company listed on the TSXV from April 2000 to December 2005.	October 9, 2007
Glenn Miller, Calgary, Alberta	Vice President of Land & Regulatory Affairs	Mr. Miller is the Vice President of Land & Regulatory Affairs. Mr. Miller has 15 years of direct energy related experience and has held management land and stakeholder affairs positions with MGM Energy, APF Energy and Hunt Oil Company.	May 29, 2009

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Trevor P. Wong-Chor, LLB Calgary, Alberta	Corporate Secretary	Since September 17, 2004, Barrister and Solicitor with Davis LLP. From October 1998, to September 17, 2004, Barrister and Solicitor with Borden Ladner Gervais LLP, and its predecessor firms.	March 9, 2006

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Corporate Governance and Compensation Committee.
- (3) Member of the Reserves Committee.

The Corporation has also received the consent of the board and Mr. Sidney Dykstra to join the board of the Corporation at the next Annual General and Special Meeting expected to be held on December 2, 2009.

Mr. Dykstra was the President and Chief Executive Officer of OPTI Canada Inc. from June 2001 until April 2009. During this period OPTI initiated, financed and developed the OPTI/Nexen Long Lake project. From June 2000 to March 2001, Mr. Dykstra was the President of Hunt Oil Company of Canada Inc. Mr. Dykstra, a co-founder of Newport Petroleum Corporation, was the President and Chief Operating Officer of Newport Petroleum Corporation from 1997 to 2000, the Executive Vice President of Newport Petroleum Corporation from 1994 to 1997 and the Vice President, Engineering of Newport Petroleum Corporation from 1992 to 1994. From 1980 to 1992, Mr. Dykstra held various positions with Suncor, Inc., was the Manager of exploitation for Pancontinental Oil Ltd. and was an independent consultant with Maranta Resources Ltd. Mr. Dykstra is currently a director of Cinch Energy Corp. and is a past Governor of the Canadian Association of Petroleum Producers. Mr. Dykstra is a professional engineer in Alberta and holds numerous professional affiliations and memberships.

The directors listed above will hold office until the next annual meeting of the Corporation or until their successors are elected or appointed.

As at October 28, 2009, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 1,521,017 Common Shares or approximately 1.25% of the issued and outstanding Common Shares of the Corporation and Subscription Receipts to acquire 390,000 Common Shares upon completion of the Proposed Acquisition. Information as to holdings of insiders of the Corporation may be found on www.sedi.ca.

Corporate Cease Trade Orders or Bankruptcies

Other than as set forth below, no director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within 10 years before the date of this Annual Information Form, has been, a director or executive officer of any corporation that, while that person was acting in that capacity:

- (a) was the subject of a cease trade or similar order, or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days;
- (b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the corporation being the subject of a cease trade or similar order or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

- (c) within a year of that person ceasing to act in such capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

David M. Antony was a director and officer of Earlyrain Inc. Earlyrain Inc. was subject to a cease trade order from the Alberta Securities Commission and British Columbia Securities Commission for failure to file financial statements. The cease trade order was issued on June 11, 2002 by the British Columbia Securities Commission and on June 21, 2002 by the Alberta Securities Commission. Earlyrain Inc. was dissolved in 2005.

Howard Bolinger was a director of Pure Lean Inc. Pure Lean Inc. was subject to a cease trade order from the Alberta Securities Commission and British Columbia Securities Commission for failure to file financial statements. The cease trade order was issued on July 27, 2004 by the British Columbia Securities Commission and on August 13, 2004 by the Alberta Securities Commission.

Personal Bankruptcies

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has within 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person.

Penalties or Sanctions

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to:

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain directors and officers of the Corporation and its subsidiaries are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Some of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation. In particular, certain of the directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or

agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

PROMOTERS

David M. Antony may be considered to be a promoter of the Corporation as he took the initiative in reorganizing the Corporation. As of the date of this Annual Information Form, Mr. Antony beneficially owns 642,917 Common Shares, representing approximately 0.5% of the issued and outstanding Common Shares. Mr. Antony also holds 100,000 Subscription Receipts which convert into Common Shares upon the closing of the Proposed Acquisition and options to purchase:

- (a) 200,000 Common Shares at an exercise price of \$0.30 per Common Share until March 9, 2011;
- (b) 435,000 Common Shares at an exercise price of \$0.50 per Common Share until November 22, 2011;
- (c) 300,000 Common Shares at an exercise price of \$3.15 per Common Share until June 7, 2012;
- (d) 400,000 Common Shares at an exercise price of \$1.90 per Common Share until January 6, 2013;
- (e) 200,000 Common Shares at an exercise price of \$1.05 per Common Share until April 29, 2013; and
- (f) 390,000 Common Shares at an exercise price of \$0.10 per Common Share until December 12, 2016.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other as set forth below, there are no legal proceedings to which the Corporation is a party or of which any of its property is the subject and there are no such proceedings known to the Corporation to be contemplated.

The Corporation has commenced an action for approximately \$500,000 against two former executives of Rochester related to the repayment of certain amounts improperly paid to such individuals by Rochester. The former executives have defended the action claiming they are entitled to keep the monies paid, and have also counterclaimed against the Corporation for the wrongful dismissal and payment of the sum of approximately \$140,000. Management, upon advice from legal counsel, believe the counterclaim is without merit.

There are no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during legal proceedings material to the Corporation to which the Corporation is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Corporation to be contemplated during the financial year ended June 30, 2009. There are no legal proceedings to which the Corporation is a party or of which any of its property is the subject and there are no such proceedings known to the Corporation to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set forth herein, or as previously disclosed, the Corporation is not aware of any material interests, direct or indirect, by way of beneficial ownership of securities or otherwise, of any director or executive officer or any shareholder holding more than 10% of the Common Shares or any associate or affiliate of any of the foregoing in any transaction within the three most recently completed financial years or during the current financial year or any proposed or ongoing transaction of the Corporation which has or will materially affect the Corporation.

In September of 2007, the Corporation acquired the September Assets from Bounty, who at such time held greater than 10% of the issued and outstanding Common Shares; in addition, Mr. Jon Clark is both an employee of Bounty and a director of the Corporation. See "*GENERAL DEVELOPMENT OF THE BUSINESS - Three Year History*".

TRANSFER AGENT AND REGISTRARS

Valiant Trust Company is the transfer agent and registrar of the Common Shares and the register of transfers of Common Shares is maintained in Calgary, Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into during the financial year ended June 30, 2009 (or that were effective in the financial year ended June 30, 2009) that is still in effect are as follows:

1. the Rochester Acquisition agreement;
2. the Saxony Acquisition agreement; and
3. the Underwriting Agreement dated October 23, 2009.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than McDaniel and GLJ, the Corporation's independent engineering evaluators and Meyers Norris Penny LLP, the Corporation's auditors.

As at the date of hereof, the principal evaluators of McDaniel and GLJ, the independent reserves evaluators, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

As at the date of hereof, the partners and associates of Meyers Norris Penny LLP, Chartered Accountants, the external auditors of the Corporation, as a group, do not beneficially own any outstanding Common Shares. Meyers Norris Penny LLP is independent in accordance with the auditors' rules of professional conduct in Canada.

Trevor Wong-Chor, the Corporate Secretary of the Corporation, is a lawyer at Davis LLP, which law firm provides legal services to the Corporation. As of the date hereof, the associates and partners of Davis LLP, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.SEDAR.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the most recent Information Circular.

Additional information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended June 30, 2009, which are also available on SEDAR.

SCHEDULE "A"
REPORT OF INDEPENDENT QUALIFIED RESERVES EVALUATORS (FORM 51 -101 F2)

October 26, 2009

Southern Pacific Resource Corp.

Suite 430, 550 – 6th Avenue S.W.

Calgary, Alberta

T2P 0S2

Attention: The Board of Directors of Southern Pacific Resource Corp.

Re: **Form 51-101F2**

**Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Southern Pacific Resource Corp. (the “Company”)**

To the Board of Directors of Southern Pacific Resource Corp. (the “Company”):

1. We have evaluated the Company’s McKay Area reserves data as at July 1, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at July 1, 2009 estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”) prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended July 1, 2009, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue \$MM (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
August 31, 2009	Canada	-	122	-	122

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.



P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Southern Pacific Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at June 30, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at June 30, 2009, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended June 30, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary August 10, 2009	Canada	-	14,099	-	14,099

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, August 10, 2009

A handwritten signature in blue ink, appearing to read 'L. Herchen', is placed over a light gray rectangular background.

Leonard L. Herchen, P. Eng.
Manager, Engineering

**SCHEDULE “B”
REPORT OF MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE (FORM 51-101F3)**

Management of Southern Pacific Resource Corp. (the “**Corporation**”) are responsible for the preparation and disclosure of information with respect to the Corporation’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

1. proved and proved plus probable oil and gas reserves estimated as at June 30, 2009 using forecast prices and costs; and
2. the related estimated future net revenue; and
3. proved oil and gas reserves were estimated as at June 30, 2009 using constant prices and costs; and
4. the related estimated future net revenue (not included in this report).

An independent qualified reserves evaluator has evaluated the Corporation’s reserves data. The report of the independent qualified reserves evaluator will be filed with the securities regulatory authorities concurrently with this report.

The reserves committee of the board of directors of the Corporation has:

1. reviewed the Corporation’s procedures for providing information to the independent qualified reserves evaluator;
2. met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
3. reviewed the reserves data with management and the independent qualified reserves evaluator.

The reserves committee of the board of directors has reviewed the Corporation’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management.

The board of directors, on recommendation of the reserves committee, has approved:

1. the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
2. the filing of the report of the independent qualified reserves evaluation on the reserves data; and
3. the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*Byron Lutes*"

**Byron Lutes, Chief Executive Officer,
President and Director**

(signed) "*Howard Bolinger*"

Howard Bolinger, Chief Financial Officer

(signed) "*David M. Antony*"

David M. Antony, Chairman and Director

(signed) "*Tibor Fekete*"

Tibor Fekete, Director

Dated: October 28, 2009