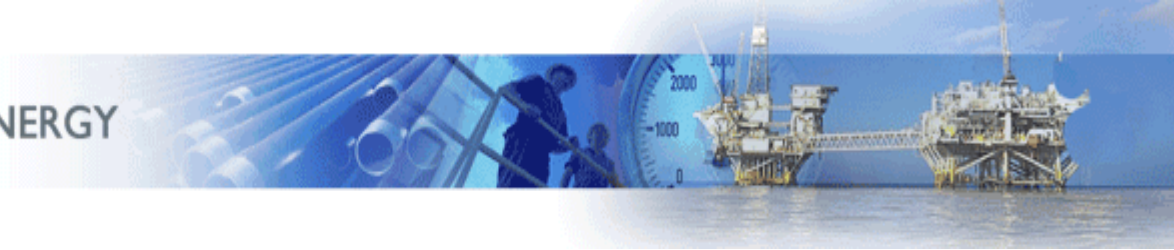




PACIFIC ENERGY



MANAGEMENT'S DISCUSSION AND ANALYSIS
For the year ended December 31, 2008
(Under Creditor Protection as of March 9, 2009)
(Restated)



MANAGEMENT'S DISCUSSION AND ANALYSIS

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(RESTATED)

The following discussion and analysis of our operating results and financial position should be read in conjunction with our audited financial statements for the fiscal years ended December 31, 2008 and 2007 and related notes (collectively, "financial statements"), which have been prepared in accordance with accounting principles generally accepted in Canada ("GAAP"). This Management's Discussion and Analysis is current through March 20, 2009 with amendments current through May 6, 2009.

Forward-Looking Statements

Certain information in this discussion and analysis contains or incorporates by reference forward-looking statements within the meaning of applicable securities legislation.

These forward looking statements include, among others, statements regarding:

- anticipated effects and outcome of bankruptcy and protection proceedings;
- business strategy and plans or budgets;
- business plans for drilling, exploration and development;
- the estimated amounts and timing of capital expenditures;
- the estimated timing of development, including new production;
- the anticipated schedule for commissioning of pipelines;
- royalty rates and exchange rates; and
- other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.

MANAGEMENT'S DISCUSSION AND ANALYSIS

These types of statements, as well as statements related to bankruptcy and insolvency proceedings, results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production, environmental risks, regulatory matters, the magnitude of oil and gas reserves, future wells to be drilled or returned to production in our Beta and Alaska operations including our joint drilling program with Chevron, the Corsair exploration prospect, and debtor-in-possession financing should all be treated as forward-looking statements derived by management's opinion and the use of outside consultants.

Often, but not always, forward-looking statements use words or phrases such as: *"expects"*, *"does not expect"* or *"is expected"*, *"anticipates"* or *"does not anticipate"*, *"plans"* or *"planned"*, *"estimates"* or *"estimated"*, *"projects"* or *"projected"*, *"forecasts"* or *"forecasted"*, *"believes"*, *"intends"*, *"likely"*, *"possible"*, *"probable"*, *"scheduled"*, *"positioned"*, *"goals"* or *"objectives"*, or state that certain actions, events or results *"may"*, *"could"*, *"would"*, *"might"* or *"will"* be taken, occur or be achieved.

Various assumptions were used in drawing the conclusions or making the forecasts and projections contained in the forward-looking statements throughout this management's discussion and analysis. In particular, statements which discuss our business plans for drilling, exploration and development in 2009 and beyond assume that the extraction of crude oil, natural gas and natural gas liquids remains economic and that we continue as a going concern. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by us and described in the forward-looking statements. These risks and uncertainties include without limitation, those described in the "Risk Factors" section of our most recent Annual Information Form ("AIF") and the following:

- our ability to continue as a going concern;
- our ability to obtain listing on an alternative exchange;
- our ability to comply with the terms of our debtor-in-possession financing;
- our ability to develop, prosecute, confirm and consummate one or more plans of reorganization with respect to the chapter 11 bankruptcy cases we and our subsidiaries filed in March 2009;
- risks associated with third parties seeking and obtaining court approval to terminate or shorten the automatic stay and/or the exclusivity period for us to propose and confirm one or more plans of reorganization, for the appointment of a chapter 11 trustee or to convert the cases to chapter 7 liquidation cases;
- our ability to obtain and maintain normal terms with vendors and service providers;
- our ability to maintain contracts that are critical to our operations;
- the potential adverse impact of the chapter 11 cases on our liquidity or results of operations and on the value of our pre-petition liabilities and common stock;

MANAGEMENT'S DISCUSSION AND ANALYSIS

- our ability to fund and execute our business plan and meet our substantial capital requirements;
- our ability to attract, motivate and/or retain key executives and employees;
- our ability to attract and retain customers and suppliers;
- volatility and uncertainty of oil, natural gas and other commodities prices;
- competitive pressure among companies in the oil and natural gas industry may increase significantly;
- changes in the interest rate environment may adversely affect our asset values or increase our borrowing costs;
- general economic conditions, whether nationally or in the market areas in which we conduct business, may be less favorable than expected;
- results of our hedging transactions and other risk mitigation strategies;
- risk of impairment of our petroleum and natural gas properties;
- the effects of government regulation or legislation or shifts in government policy;
- the reserve estimates presented will differ from our actual results;
- the uncertainty of the productivity of drilled oil and natural gas wells may adversely affect our ability to produce oil and/or natural gas in commercial quantities;
- weather disturbances or natural occurrences such as earthquakes or volcanic eruptions could disproportionately affect our production or transportation due to our geographic concentration;
- significant changes in the cost or availability of gathering systems, pipelines and processing facilities may affect our ability to produce and market oil and natural gas; and
- costs or difficulties related to the integration of businesses or opportunities we acquire may be greater than expected, and operating results following any acquisitions may not be as expected; and
- adverse changes may occur in the securities markets generally.

Readers are cautioned that the foregoing list of risks and uncertainties is not exhaustive. Additional information on these and other factors which could affect our operations or financial results is included under the heading “*Risk Factors*” in our AIF.

Forward-looking statements are based on the estimates and opinions of our management at the time the statements are made. Except to the extent required by applicable law, we assume no obligation to update forward-looking statements should circumstances or management's

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estimates or opinions change.

Additional information about us, including our AIF, is available for viewing on SEDAR at www.sedar.com.

Amendments to the MD&A

As required under National Instrument Form 51-102, we are required to evaluate the effectiveness of our internal controls over financial reporting and our disclosure controls and procedures we have in place and to determine if these controls are adequate to ensure timely and accurate reporting of financial information. During our annual review, we cited material weaknesses, but failed to specifically identify the weakness, the potential impact it may have on financial reporting, and what if any remedies we are taking to address the material weaknesses. We have updated the Internal Disclosure Controls section of this document to comply with the disclosure requirement.

Insolvency Proceedings

On March 9, 2009, we and our wholly-owned subsidiaries filed with the U.S. Bankruptcy Court for the District of Delaware ("Bankruptcy Court") voluntary petitions for reorganization under chapter 11 of the United States Bankruptcy Code ("chapter 11"). On March 10, 2009, the Bankruptcy Court entered Interim Order for In re: Pacific Energy Resources Ltd., et al., (1) approving senior secured superpriority postpetition financing (see "*DIP Facility*" below), (2) authorizing use of cash collateral, (3) granting liens and providing superpriority administrative expense status, (4) granting adequate protection, (5) modifying automatic stay, and (6) scheduling a final hearing. A final hearing on the DIP Facility and other matters is scheduled for April 8, 2009. Under the Interim Order, we received customary authority from the Bankruptcy Court to enable us to continue operating our business in the ordinary course. The DIP Facility, combined with our operating revenue, is expected to provide sufficient liquidity to fund working capital, meet ongoing obligations and ensure that normal operations continue without interruption during our restructuring.

In addition to obtaining bankruptcy protection in the U.S. on March 10, 2009, we obtained protection in Canada under the *Companies' Creditors Arrangement Act* (Canada) (the "CCAA") on March 12, 2009. CCAA protection will also stay creditors, suppliers and others from enforcing any rights against us. The pursuant to an initial order granted on March 12, 2009 by the Supreme Court of British Columbia ("BCSC"), the BCSC has granted CCAA protection for an initial period expiring April 9, 2009, to be extended thereafter as the BCSC deems appropriate. If by April 9, 2009, we have not filed a restructuring plan or obtained an extension of the CCAA protection, creditors and others will no longer be stayed from enforcing their rights against us.

While under CCAA protection, our management remains responsible for our day-to-day operations. The BCSC has appointed Todd McMahon Inc. as a monitor, who will be responsible for monitoring the course and conduct of the U.S. proceedings as well as our ongoing operations and reporting to the BCSC.

The chapter 11 and CCAA protection are collectively referred to as the "Insolvency

MANAGEMENT'S DISCUSSION AND ANALYSIS

Proceedings.”

Economic dependence and going concern

The financial statements have been prepared using the same Canadian GAAP as applied by us prior to the Insolvency Proceedings described above. While we have filed for and been granted creditor protection, the financial statements continue to be prepared using the going concern concept, which assumes that we will be able to realize our assets and discharge our liabilities in the normal course of business for the foreseeable future. The Insolvency Proceedings provide us with a period of time to stabilize our operations and financial condition and develop a restructuring plan. Debtor-in-possession (“DIP”) financing has been approved on an interim basis by the Bankruptcy Court and is available, subject to borrowing conditions, as described in “Debt”. Management believes that these circumstances make the going concern basis appropriate. However, it is not possible to predict the outcome of these proceedings and, as such, realization of assets and discharge of liabilities is subject to significant uncertainty. Accordingly, substantial doubt exists as to whether we will be able to continue as a going concern. Further, it is not possible to predict whether the actions taken in any restructuring will result in improvements to our financial condition sufficient to allow us to continue as a going concern. If the going concern basis is not appropriate, adjustments would be necessary to the carrying amounts and/or classification of assets and liabilities, and to the expenses in our financial statements.

The accompanying financial statements do not purport to reflect or provide for the consequences of the Insolvency Proceedings. In particular, such financial statements do not purport to show: (a) as to assets, their realizable value on a liquidation basis or their availability to satisfy liabilities; (b) as to pre-petition liabilities, the amounts that may be allowed for claims or contingencies, or the status and priority thereof; (c) as to shareholders accounts, the effect of any changes that may be made in our capitalization; or (d) as to operations, the effect of any changes that may be made in our business.

While we are under creditor protection, we will make adjustments to the financial statements to isolate assets, liabilities, revenues, and expenses related to the reorganization and restructuring activities so as to distinguish these events and transactions from those associated with the ongoing operation of the business. Further, claims allowed arising under the Insolvency Proceedings may be recorded as liabilities and presented separately on the consolidated balance sheets. If a restructuring occurs and there is substantial realignment of the equity and non-equity interests in our company, then we will be required, under Canadian GAAP, to adopt “fresh start” reporting. Under fresh start reporting, we would undertake a comprehensive re-evaluation of our assets and liabilities based on the reorganization value as established and confirmed in the restructuring plan. The financial statements do not present any adjustments that may be required during the period that we remain under creditor protection, or that may be required under fresh start reporting.

In accordance with Canadian GAAP appropriate for a going concern, petroleum and natural gas properties and equipment are carried at cost less accumulated depreciation, depletion and amortization and any impairment losses and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts of such assets may not be recoverable. The series of events that led us to the Insolvency Proceedings and the events since then triggered impairment tests for its petroleum and natural gas properties and equipment. In the

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fiscal year ended December 31, 2008, we recorded impairment charges of \$131.4 million including \$126.1 million for certain of our Alaska petroleum and natural gas properties. We made assumptions, such as oil prices, capital costs and operating costs in estimating the future cash flows expected from the use of our assets. There can be no assurance that expected future cash flows will be realized or will be sufficient to recover the remaining carrying amount of long-lived assets.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. The Insolvency Proceedings materially affect the degree of uncertainty associated with the measurement of many amounts in the financial statements. More specifically, the proceedings could impact the recoverability tests and fair value assumptions used in the impairment test of petroleum and natural gas properties and equipment.

In light of the Insolvency Proceedings, current oil prices and current capital market conditions, it is unlikely that our existing common shares will have any material value following the approval of a restructuring.

Overview

We are an independent oil and gas production and development company with operations in both offshore California and onshore and offshore Alaska. We are focused on the exploitation, exploration and development of our oil and gas properties. Our corporate offices are located in Long Beach, California.

In March 2007, we acquired the Beta Unit from Aera Energy LLC (a Shell-ExxonMobil joint venture), SWEPI LP (a Shell subsidiary) and Noble Energy, Inc. The acquisition agreements required us to deposit \$90.0 million in U.S. Treasury notes in a supplemental bond decommissioning trust account for abandonment and decommissioning purposes, provide bonds of \$1.8 million, make payments totaling \$6.93 million after certain production levels are met as defined in the purchase agreements, and enter a new lease agreement with Mineral Management Services ("MMS") of the United States Department of the Interior. On March 25, 2008, we were granted a new 20-year lease for the San Pedro Bay pipeline from the California State Lands Commission.

We financed the acquisition of the Beta Unit with debt from an affiliate of The Goldman Sachs Group, Inc. and affiliates of Silver Point Finance, LLC (see "Debt") and approximately \$82.7 million in proceeds from the sale of 73.5 million shares of our common stock that were accompanied by warrants to purchase 36.7 million shares of our common stock. Assets in the Beta Unit include leases OCS-P 300, 301 and 306 and three platforms that handle production from these leases: two production platforms (Ellen and Eureka) with one processing platform (Elly) capable of supporting both production platforms. Platform Eureka had been shut-in since 1999 at which time it was producing nearly 4,600 barrels of oil equivalent per day ("boe/d"). We reactivated Platform Eureka with first production resuming April 2008. Our California operations also include operation of the 100%-owned San Pedro Bay pipeline which runs 17 miles from the Beta field to our onshore pump station located in the Port of Long Beach.

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We closed the acquisition of our Alaska assets from Forest Oil Corporation ("Forest Oil") on August 27, 2007. Total consideration consisted of \$405.0 million in cash (consisting of \$400.0 million paid to Forest Oil and approximately \$5.0 million in transaction costs), 10.0 million shares of our common stock, and a senior subordinated seller note issued to Forest Oil with a net present value at closing of approximately \$29.3 million. The acquisition consisted of the purchase of nine producing fields (five operated), three onshore facilities, seven platforms and six platform drilling rigs. In addition, we acquired 972,640 net acres of undeveloped leasehold (of which we currently hold 587,423 acres following the termination of an exploration license in November 2007) and a 50% interest in Cook Inlet Pipe Line Company ("CIPL"). The non-operated producing properties are operated by a subsidiary of Chevron Corporation ("Chevron"). CIPL is also operated by Chevron. Our Alaska operations are managed from our office in Anchorage, Alaska.

Also included in the Alaska acquisition was the Corsair exploration prospect. The four Corsair Unit exploration leases that expired on May 1, 2008, and which were included in an application by us to expand the Corsair Unit that was denied by the State of Alaska, are still the subject of a pending appeal by us. However, these four leases, and the four additional leases that comprise the Corsair Unit, are the subject of a current proposal by the State of Alaska to be included in a new multi-prospect unit that would renew the expired leases and extend the term of the Corsair Unit pending the drilling of exploratory well by a new, yet to be determined, operator for the new multi-prospect unit.

In July 2008, we divested our onshore California properties, which produced from fields located in the Los Angeles and San Joaquin Basins.

See "Future Prospects" below for a discussion of our restructuring process.

Overall Performance

The full year 2008 represented a year of opportunity and a year of challenge for us. We began the year with significantly increasing oil prices and ended the year with significantly decreasing oil prices. Operationally, we had significant success at the Beta Unit, returning Platform Eureka to partial production, and thereby increased our production by 103% to 3,400 boe/d in the fourth quarter of 2008 compared to the prior year period and reduced our lease operating expenses by 40% to \$23 per barrel of oil equivalent ("boe") for the same period. However, as the capital markets deteriorated, compounded by oil prices falling dramatically, our efforts to restructure our outstanding debt by raising equity, refinancing the debt at more attractive rates and accessing the surety market to release restricted cash proved unsuccessful.

January 1, 2008 to March 20, 2009 Highlights

- In January 2008, we completed an incentive warrant offering for net proceeds of approximately \$19.1 million.
- In February 2008, the MMS awarded us the 2007 Safety Award for Excellence for the California district for our operation of Platforms Elly, Ellen and Eureka.

MANAGEMENT'S DISCUSSION AND ANALYSIS

- In March 2008, we announced regulatory approval from the MMS to complete the initial return to production of Platform Eureka.
- In April 2008, we obtained a 20-year right of way extension with the State of California for our San Pedro Bay pipeline.
- In April 2008, we completed the partial return of Platform Eureka to production after only 13 months as operator. The platform had been shut-in since 1999.
- In May 2008, we announced the sale of our onshore California assets as part of our debt reduction program. The two sales transactions closed in July 2008, for net proceeds of approximately \$127.5 million. Approximately \$63 million was used to pay down debt, with an additional \$30 million used to terminate and settle hedge contracts. The balance of the funds received were largely added to our working capital.
- In June 2008, we announced that we met our phase I production targets for Platform Eureka, achieving production in excess of 1,200 boe/d for a combined Beta Unit output totaling approximately 3,000 boe/d.
- In October 2008, we reached our phase II production target for Platform Eureka, with production reaching approximately 2,000 boe/d.
- On December 19, 2008, we amended our credit and hedging facilities by means of Forbearance Agreements, which after extension ran through February 17, 2009. On March 9, 2009, we filed for chapter 11 protection as described in "Insolvency Proceedings." We closed on DIP Financing on March 11, 2009 as described in "Debt" below.

Year-over-Year Operational Highlights

For the year ended December 31, 2008, for continuing operations:

- Production increased 129.1% to 6,816 boe/d, reflecting a full year of contribution from assets acquired in 2007 (Beta Unit, March 1, 2007; and Alaska assets, August 27, 2007) and from the partial return to production of Platform Eureka in the Beta Unit.
- Realized oil prices before hedging losses increased 24.5% to \$92 per barrel. After hedging losses, realized oil prices increased 16.0% to \$74 per barrel.
- Lease operating expenses per boe for the year ended December 31, 2008 decreased on a company-wide basis by 15.9% to \$39, with Beta lease operating expenses decreasing by 28.6% to \$30.
- Approximately \$37.2 million was spent on capital expenditures, representing a 148.4% increase over the 2007 total.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Results of Operations

The key metrics our management uses to analyze our business include: production volumes, hedging results, lease operating expenses (both dollars of spending and per boe), general and administrative spending, interest expense and debt level, and capital spending efficiency in terms of value for dollars spent and investment return.

Results of Operations—For Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Factors Affecting Comparability

We acquired the Beta Unit on March 1, 2007 and the Alaska assets on August 27, 2007. In July 2008, we divested of our onshore California producing properties; their results prior to the disposition are shown as discontinued operations for both 2008 and 2007. Our results of operations from period to period are not comparable because of the effects of these acquisitions and dispositions. All current and comparative results are presented and discussed on a continuing operations basis only unless otherwise indicated. The 2008 and 2007 financial results of the properties sold in July 2008 are included in “net loss from discontinued operations”, and not included in individual revenue and expense lines in our consolidated statements of operations, nor in the discussion of these individual line items below. The results of discontinued operations are discussed in that section below.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Revenues

	(dollar amounts are in thousands)		
	<u>For the Year Ended</u>		<u>% Change From</u>
	<u>December 31,</u>		<u>December 31,</u>
	<u>2008</u>	<u>2007</u>	<u>2007</u>
Oil and gas production revenue	\$ 226,245	\$ 84,257	168.5%
Royalties	(49,457)	(15,320)	222.8%
Realized loss on derivatives	(42,440)	(10,693)	296.9%
	<u>\$ 134,348</u>	<u>\$ 58,244</u>	<u>130.7%</u>
Total oil equivalent production - boe/d			
California ⁽¹⁾	2,652	1,470	80.4%
Alaska ⁽²⁾	4,164	1,505	176.6%
Total	<u>6,816</u>	<u>2,975</u>	<u>129.1%</u>
Oil sales (bbls/d)			
California ⁽¹⁾	2,652	1,470	80.4%
Alaska ⁽²⁾	3,933	1,633	140.9%
Total	<u>6,585</u>	<u>3,103</u>	<u>112.2%</u>
Natural gas sales (mcf/d)			
Alaska	2,193	-	N/A
Total oil equivalent sales (boe/d)			
California ⁽¹⁾	2,652	1,470	80.4%
Alaska ⁽²⁾	6,126	1,633	275.2%
Total	<u>8,778</u>	<u>3,103</u>	<u>182.9%</u>
Average NYMEX light sweet crude oil per barrel	\$ 99.67	\$ 72.31	37.8%
Realized price per barrel of oil			
Before hedging	\$ 92.08	\$ 73.96	24.5%
After hedging	\$ 74.47	\$ 64.18	16.0%

⁽¹⁾ Production and sales for the year ended December 31, 2007 for Beta is from the date of acquisition, March 1, 2007, divided by 365 days in the year. Beta sales and production from March through December 2007 was 1,753 bbls/d.

⁽²⁾ Production and sales for the year ended December 31, 2007 for Alaska is from the date of acquisition, August 27, 2007, divided by 365 days in the year. Alaska production from September through December 2007 was 4,504 bbls/d and sales for the same period were 4,885 bbls/d.

Oil and Gas Production Revenue: Compared to 2007, our \$226.2 million of total revenue before hedging losses for 2008 was up 168.5% due to a 129.1% increase in oil sales volume and a 24.5% increase in realized price of oil before hedging losses. The increase in volume resulted from Platform Eureka partially returning to production and from the additional production coming from full year Beta and Alaska operations. The realized price before hedging loss was \$92 per barrel in 2008 compared to \$74 per barrel in 2008.

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Royalties: Royalty expense increased as a result of higher oil prices during the first half of 2008 in particular, increased production and higher royalty rates. Royalty expense is a function of oil prices and royalty rates. Increased production for the year reflects the partial year in 2007 following the acquisition of the Beta Unit and Alaska assets, together with production increases in the Beta Unit in 2008. Finally, additional overriding royalties were granted to our lenders in mid-July 2008 in connection with the divestiture of our onshore California properties. Royalties averaged 21.9% of oil and gas production revenues in 2008 compared to 18.2% in 2007.

Hedging Losses: Our realized loss on derivatives increased \$31.7 million to \$42.4 million in 2008. In connection with both the Beta Unit and Alaska asset acquisitions in 2007, a portion of future oil sales was sold forward through swap contracts. Fiscal 2008 included a full year of operations following the Beta and Alaska acquisitions. Hedging losses occur when physical oil produced is sold at spot market prices greater than the hedge price. Adding the realized price included in oil and gas production revenues above with the hedging loss, results in oil production being sold at the hedge price, subject to any local price and quality differentials. The 24.5% increase in average realized prices for our crude oil from the year ago period created a largely equivalent increase in hedging losses for that portion of our sales that was hedged. Average price realized after hedging losses was \$74 per barrel in 2008 compared to \$64 in 2007.

Note that the \$29.7 million paid to extinguish the hedge position for the properties sold in July 2008 was charged to the liability account, which liability had been created through expense charges in discontinued operations over the period of time between the establishment of the hedge position and the termination of that position. This amount was not part of the hedging losses discussed in the prior paragraph.

Revenue – Interest and Dividends, Loss from Equity Investment and Other Revenue

(dollar amounts are in thousands)

	<u>For the Year Ended</u>		<u>% Change From</u>
	<u>December 31,</u>		<u>December 31,</u>
	<u>2008</u>	<u>2007</u>	<u>2007</u>
Interest and dividends	\$ 5,919	\$ 2,916	103.0%
Loss from equity investment	\$ (1,863)	\$ (321)	480.4%
Other revenue	\$ 137	\$ 326	-58.0%

Interest and Dividends: Interest and dividends revenue is earned on investment accounts on deposit to secure performance bonds and abandonment liabilities. These amounts are not available to us for current operations; rather, they accrue toward satisfying the future liabilities.

Loss from Equity Investment: We own a 50% interest in CIPL, which transports oil for us and third parties in Alaska. The increased loss reflects a full year of ownership as well as increased maintenance costs in 2008.

Other Revenue: This totaled \$0.1 million in 2008 compared to \$0.3 million in 2007.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Expenses – Production, Transportation and General and Administrative

	(dollar amounts are in thousands)		
	For the Year Ended		% Change From
	December 31,		December 31,
	2008	2007	2007
Lease operating expenses (per boe produced)			
California	\$ 30.29	\$ 42.44	-28.6%
Alaska	44.33	49.92	-11.2%
Weighted average	38.87	46.23	-15.9%
Lease operating expenses	\$ 96,950	\$ 50,201	93.1%
Direct costs	(82)	3,011	-102.7%
Total production expenses	\$ 96,868	\$ 53,212	82.0%
Transportation	\$ 4,581	\$ 2,359	94.2%
General and administrative	\$ 15,170	\$ 10,147	49.5%

Production Costs: Total lease operating expenses increased 93.1% to \$97.0 million, reflecting a full year of the Beta Unit and the Alaska assets in 2008. Sales volumes increased 112.2%. On a per barrel basis, however, lease operating expenses decreased 15.9% to \$39 boe in 2008 due to the increased production from Platform Eureka. The Beta Unit includes three platforms; Elly, Ellen, and Eureka, which have a significant element of fixed costs. Beta's lease operating expenses declined 28.6% to \$30 per boe in 2008, while Alaska's lease operating expenses declined 11.2% to \$44 per boe in 2008.

In addition to lease operating expenses, production costs include other direct costs that were down from \$3.0 million in 2007 to \$0.1 million in 2008. Costs of operating the San Pedro Bay pipeline decreased from \$2.5 million in 2007 to \$1.2 million in 2008, reflecting decreased maintenance costs in 2008. In addition, increased Alaska crude oil sales in 2008 generated a positive "gravity" adjustment, reflecting the higher quality of crude oil relative to the benchmark used for the revenue determination.

Transportation: Transportation expense is the cost associated with paying the pipeline tariff to CIPL for transporting our production in Alaska to the Drift River Terminal. The tariff increased in the second quarter of 2008 from \$2.74 per barrel to \$3.34 per barrel. The increase in expense is due to a full year of Alaska production in 2008 coupled with the increase in the tariff rate.

General and Administrative ("G&A"): G&A expense is up from the year ago period due to the increase in headcount and office space as a result of the Alaska acquisition. Costs increased in the corporate office as well as through a full year of Alaska G&A costs.

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Expenses - Stock Compensation and Liquidated Damages

(dollar amounts are in thousands)

	For the Year Ended		% Change From
	December 31,		December 31,
	2008	2007	2007
Stock compensation	\$ 6,339	\$ 3,468	82.8%
Liquidated damages	\$ 4,080	\$ 6,050	-32.6%

Stock Compensation: This non-cash expense increased 82.8% to \$6.3 million in 2008 due to the granting of additional options to officers and employees. The expense is calculated based on the estimated intrinsic value of the underlying shares at the date of grant of options, as determined by using the Black-Scholes method, which expense is then spread over the vesting period of the options. The subsequent change in market price for our common shares after the date of grant does not impact the expense over the vesting period.

Liquidated Damages: The registration rights agreements that we entered into in connection with the equity and debt financings relating to the Beta Unit acquisition required us to, among other things, register for resale the common stock and shares underlying warrants issued in those financings and to maintain the effectiveness of the registration statement for an extended period of time. Because our acquisition of the Alaska assets on August 27, 2007 necessitated that we include in the registration statement audited financial information regarding the Alaska assets, which information was unavailable at that time, we did not meet the August 29, 2007 filing deadline for the registration statement.

We initially were subject to liquidated damages assessments of 1.0% (capped at 10.0%) of the number of shares of common stock issued in the equity financing related to the Beta Unit acquisition and still held by the original holders as of the end of each 30 days of non-compliance, subject to pro ration for partial months.

We filed the registration statement with the U.S. Securities and Exchange Commission in February 2008. However, our dispositions of assets in July 2008 necessitated further extensive revisions to the financial and other information contained in the registration statement, and the registration statement was not finalized or declared effective. However, effective February 20, 2008, when our shares that were trading under the symbol PFE.S became PFE-listed shares, non-affiliate holders of those shares became able to trade them without further restriction and therefore were no longer entitled to receive further liquidated damages shares, and affiliate holders became able to trade them subject to compliance with Rule 144 under the Securities Act of 1933 or another registration exemption and therefore continued to receive liquidated damages shares until June 2008 (the tenth month of non-compliance).

We recorded liquidated damages of \$6.1 million in 2007 and \$4.1 million in 2008. The total number of shares issued for liquidated damages was 5.2 million. The liquidated damages expense represents the fair value of the underlying damages shares that were issued. The liquidated damages expense decreased 32.6% year-over-year due to a reduced number of damages shares issued in 2008 as compared to 2007 and a lower stock price. This is a non-cash expense. No further expense is anticipated in future periods, as the obligation to issue additional shares ended in June 2008.

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Expenses – Interest

(dollar amounts are in thousands)

	For the Year Ended		% Change From
	December 31,		
	2008	2007	2007
Interest - cash	\$ 65,101	\$ 34,532	88.5%
Interest - non cash - paid in kind	\$ 42,389	\$ 8,269	412.6%
Interest - accretion of discounts and amortization of deferred financing costs	\$ 10,084	\$ 11,630	-13.3%
Interest - accelerated expensing of accretion and amortization of deferred financing costs	\$ 48,398	\$ -	N/A

Interest - Cash: This expense increased from \$34.5 million in 2007 to \$65.1 million in 2008. The 2007 expense included only a partial year of debt following the acquisition of the Beta Unit on March 1, 2007 and the Alaska assets on August 27, 2007. Included in the 2008 expense is a \$6.0 million covenant violation waiver fee in the first quarter of 2008 and penalties of \$20.4 million consisting of \$9.7 million in fees for the failure to syndicate the Alaska loans and accrual in 2008 of a \$10.7 million conversion fee on the balance of the Alaska credit facility expected to be outstanding on February 24, 2009.

Interest – Non-cash – Paid in Kind: A portion of the interest payable under our Alaska credit agreements is “paid in kind”, meaning is it added to the principal balance periodically. 2008 included a full year of the Alaska operations and related debt. In addition, a portion of the cash interest then outstanding was added to the principal balance on December 19, 2008 when we executed the Forbearance Agreements. For these reasons, the expense increased from \$8.3 million in 2007 to \$42.4 million in 2008.

Interest – Accretion of Discounts and Amortization of Deferred Financing Costs: This non-cash expense decreased from \$11.6 million to \$10.1 million. Included in 2007 is a partial year of debt for the Beta Unit and the Alaska assets. Debt for both acquisitions was issued at a discount, which is accreted to face value over the term of the loan. In addition, upfront fees are amortized over the term of the related loan. As discussed below, except for the amount relating to the Forest Oil note, the remaining unamortized discount and deferred financing costs were written off on March 31, 2008, which results in the no further expensing in subsequent periods.

Interest – Accelerated Expensing of Accretion and Amortization of Deferred Financing Costs: In the first quarter of 2008, unaccreted discount and unamortized deferred financing costs related to the Goldman and Silver Point notes payable were written off in the amount of \$48.4 million in order to bring the carrying value up to face value, as a result of classifying the entire note payable balance in current liabilities.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Expenses – General Exploration, Depreciation, Depletion and Amortization, and Impairment

(dollar amounts are in thousands)

	For the Year Ended		% Change From
	December 31,		December 31,
	2008	2007	2007
General exploration	\$ 2,125	\$ 11,056	-80.8%
Depreciation, depletion and amortization expense	\$ 35,601	\$ 14,482	145.8%
Impairment	\$ 131,407	\$ -	N/A

General Exploration: The 2007 expense included a significant exploration program in Wyoming whereas no such program was conducted in 2008, resulting in decrease from \$11.1 million to \$2.1 million. A portion of 2008's expense relates to the work commitments for the Corsair exploration property in Alaska.

Depreciation, Depletion and Amortization (“DD&A”): Our DD&A expense is computed based on a units-of-production basis, except for some depreciable items which are expensed on a straight-line basis. As our Beta production increased nearly 80% from the year ago period and we had a full year of Alaska production, this expense increased 145.8% to \$35.6 million.

Impairment: We incurred impairment charges of approximately \$131.4 million for the year ended December 31, 2008. Included in the impairment is \$126.1 million related to certain Alaska petroleum and natural gas properties' net book value exceeding fair values. We also recorded impairment of unproved properties of \$0.3 million related to the expiration of certain exploration leases.

In addition, we recorded a write down of oil inventories of \$5.3 million as the market value of oil inventory was lower than its carrying value at December 31, 2008.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Net income

(dollar amounts are in thousands)

	<u>For the Year Ended</u>		<u>% Change From</u>
	<u>December 31,</u>		<u>December 31,</u>
	<u>2008</u>	<u>2007</u>	<u>2007</u>
Net loss from continuing operations, after tax	\$ (323,602)	\$ (94,040)	244.1%
Loss from discontinued operations, after tax	(8,260)	(4,709)	75.4%
Gain on sale of discontinued operations, after tax	74,254	-	N/A
Total income (loss) from discontinued operations, a	65,994	(4,709)	N/M
Net loss, after tax	\$ (257,608)	\$ (98,749)	160.9%

Loss from continuing operations: Our net loss from continuing operations was \$323.6 million for 2008, a near doubling from 2007's \$94.0 million. Included in the 2008 results are impairment charges of \$131.4 million and an acceleration of expensing of accretion and amortization of deferred financing costs of \$48.4 million. Other reasons for the increased loss have been discussed above.

Loss from discontinued operations, net of tax: The operating results from discontinued operations were an \$8.3 million loss in 2008, compared to a \$4.7 million loss in 2007. The 2008 period was from January 1, 2008 through the two dates of sale in July 2008, whereas the 2007 period was a full year. The effect of higher oil prices resulted in higher operating income despite the shorter period in 2008. However, this favourable variance was more than offset by a \$5.3 million greater unrealized loss on derivatives (oil sales swap contracts).

Gain from sale of discontinued operations, net of tax: During the third quarter of 2008, we divested of our onshore California assets and reported a gain on the sale of these assets of \$74.3 million, after tax.

Net Loss: Despite realizing a significant \$74.3 million gain on sale, our net loss was \$257.6 million in 2008, compared to a net loss of \$98.7 million in 2007.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Other Opportunities

See "Future Prospects" below.

Capital Resources and Liquidity

Our primary sources of borrowings have been and are pursuant to credit agreements with affiliates of The Goldman Sachs Group, Inc. ("Goldman") and Silver Point Finance, LLC ("Silver Point"). These affiliates are also owners of a significant number of common shares and warrants, and owners of overriding royalty interests in both our Beta Unit and Alaskan assets. An affiliate of Goldman has been the counterparty for our commodity swaps. The credit and swap agreements contain covenants and restrictions, including a requirement that all cash receipts are to be deposited into lockboxes and require us to obtain Goldman or Silver Point approval for the disbursement of funds out of the lockboxes. The DIP Financing is described below.

Working capital needs tend to be modest in the exploration and production business. We collect our revenues in the month following sale which largely matches the timing of disbursements.

At February 28, 2009, PEOA owed a subsidiary of Chevron Corporation \$20.1 million. Chevron continues to bill the Company for the Company's share of the monthly costs of operating the properties. Chevron's interest is effectively secured by the Company's production and by the working interest in the jointly-owned properties in Alaska. Beginning in the fourth quarter of 2008, Chevron exercised its right to take the Company's share of production to offset against amounts owed. To date, Chevron has not taken any other action to foreclose on the Company's working interest.

Capital spending needs and opportunities can vary widely. Sustaining capital expenditures and regulatory-driven capital expenditures are two types of capital spending which must be incurred for safe operation. Investment capital spending can be increased or decreased depending on oil price and funds availability. We currently have no investment or other capital spending commitments on our operated properties. With respect to the Alaskan properties operated by Chevron, we currently are in dispute with them over the approval process for capital and expensed project spending that they as operator propose.

Our 2008 full year capital spending is detailed below:

	(dollar amounts are in thousands)		
	For the Year Ended		% Change From
	December 31,		December 31,
	2008	2007	2007
Capital expenditures			
California	\$ 17,967	\$ 14,265	26.0%
Alaska	19,277	731	2537.1%
Total	\$ 37,244	\$ 14,996	148.4%

Our capital spending during the period of the DIP Financing is limited to maintenance and regulatory-required capital only, approximately \$5.2 million together with approximately

MANAGEMENT'S DISCUSSION AND ANALYSIS

\$1.5 million for returning to production three additional wells at Platform Eureka in the Beta Unit.

Cash Flows for Years Ended December 31, 2006 and 2007

The following table summarizes our net cash provided by or used in our operating activities, investing activities and financing activities for the years ended December 31, 2008 and 2007.

	(dollar amounts are in thousands)	
	For the Year Ended	
	December 31,	
	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Cash Used In Operating Activities from Continuing Operations	\$ (31,967)	\$ (22,105)
Net Cash Provided by Discontinued Operations	13,924	11,353
Total Net Cash Used in Operating Activities	<u>(18,043)</u>	<u>(10,752)</u>
CASH FLOWS FROM INVESTING ACTIVITIES		
Petroleum and natural gas property expenditures	(38,364)	(18,946)
Cash paid for restricted and short-term investments	(7,002)	(6,085)
Business acquisitions	-	(444,013)
Net Cash Used In Investing Activities from Continuing Operations	<u>(45,366)</u>	<u>(469,044)</u>
Proceeds on sale of assets	127,693	-
Cash paid to non-controlling interest	(6,387)	-
Cash paid to terminate crude oil sales hedges	(29,678)	-
Petroleum and natural gas property expenditures	(240)	(2,358)
Net Cash Provided by Investing Activities from Discontinued Operations	<u>91,388</u>	<u>(2,358)</u>
Net Cash Provided by (Used In) Investing Activities	<u>46,022</u>	<u>(471,402)</u>
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash received for common shares issued	19,129	75,967
Net cash received for (payments on) notes payable issued	<u>(32,378)</u>	<u>398,546</u>
Net Cash Provided By (Used In) Financing Activities from Continuing Operations	<u>(13,249)</u>	<u>474,513</u>
Net Cash Used In Financing Activities Used In Discontinued Operations	<u>(20,656)</u>	<u>(114)</u>
Net Cash Provided by (Used In) Financing Activities	<u>(33,905)</u>	<u>474,399</u>
NET CHANGE IN CASH	<u>\$ (5,926)</u>	<u>\$ (7,755)</u>

Net cash used in operating activities was \$32.0 million in 2008 compared to \$22.1 million in the year ago period. Discontinued operations generated \$13.9 million in 2008 compared to \$11.4 million in 2007, reflecting significantly higher oil prices and realization of working capital on sale, partly offset by the fact that they were sold in July 2008, so 2008's results include a shorter period.

Net cash provided by investing activities in 2008 includes the transactions related to the sale of the onshore California properties, principally the net sales proceeds of \$127.7 million less the \$29.7 million related hedge termination. Capital spending in 2008 was \$38.4 million compared to \$18.9 million in 2007. The 2007 amount also includes \$444.0 million for the Alaska acquisition.

2008 capital spending in the Beta Unit was \$18.6 million. Approximately \$7.2 million was for Platform Eureka's return to production in April 2008 and \$4.2 million was for maintenance on platforms Elly and Ellen. In addition, additional 2008 investment capital spending was \$6.6 for Platform Eureka's rig refurbishment and returning additional wells to production. An additional \$0.6 million of investment capital was for feasibility studies and engineering of various cost-savings and capacity improvement initiatives.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2008 capital spending for our Alaska assets was \$19.3 million. Approximately \$1.4 million was spent on our operated for maintenance and regulatory-driven requirements. Our share of capital spending on the properties operated by Chevron was \$17.9 million.

Net cash used in financing activities in 2008 is a result of two transactions: the incentive warrant offering that we completed in January 2008, from which net proceeds were approximately \$19.1 million, and \$32.4 million of net borrowings under the Beta senior secured credit facility ("SSC Credit Facility"). The activity in 2007 reflects \$76.0 million of equity raised and \$398.5 million of debt incurred to fund a portion of the Beta Unit acquisition and to fund the Alaska acquisition. We used \$20.7 million of cash, principally to repay debt of the discontinued operations, concurrent with their sale in July 2008 and in monthly installments prior to that date.

Fourth Quarter 2008

	As of or for the Three Months Ended			% Change From	
	December 31, 2008	September 30, 2008	December 31, 2007	September 30, 2008	December 31, 2007
Operating					
Total oil equivalent production - boe/d					
California	3,404	2,905	1,680	17.2%	102.6%
Alaska	3,680	4,508	4,464	-18.4%	-17.6%
Total	7,083	7,412	6,144	-4.4%	15.3%
Oil sales (bbls/d)					
California	3,404	2,905	1,680	17.2%	102.6%
Alaska	4,048	3,550	4,109	14.0%	-1.5%
Total	7,452	6,455	5,789	15.4%	28.7%
Natural gas sales (mcf/d)					
Alaska	2,096	2,245	-	-6.6%	N/A
Total oil equivalent sales (boe/d)					
California	3,404	2,905	1,680	17.2%	102.6%
Alaska	4,397	3,924	4,109	12.1%	7.0%
Total	7,801	6,829	5,789	14.2%	34.8%
Average NYMEX light sweet crude oil per barrel	\$ 58.73	\$ 117.98	\$ 90.68	-50.2%	-35.2%
Realized price per barrel of oil					
Before hedging	\$ 51.35	\$ 111.26	\$ 83.86	-53.8%	-38.8%
After hedging	\$ 54.63	\$ 84.14	\$ 64.75	-35.1%	-15.6%
Lease operating expenses (per boe produced)					
California	\$ 24.16	\$ 28.44	\$ 38.76	-15.1%	-37.7%
Alaska	\$ 54.85	\$ 40.29	\$ 37.46	36.1%	46.4%
Weighted average	\$ 40.10	\$ 35.65	\$ 37.82	12.5%	6.0%
Income statement and other					
Total revenue before hedging gains (losses)	\$ 36,480	\$ 67,340	\$ 45,250	-45.8%	-19.4%
Hedging gains (losses)	2,246	(16,105)	(9,788)	N/M	N/M
Total revenue after hedging gains (losses)	\$ 38,726	\$ 51,235	\$ 35,462	-24.4%	9.2%
Selected expenses					
Royalties	\$ 7,050	\$ 16,824	\$ 9,538	-58.1%	-26.1%
Production ⁽⁵⁾	26,546	21,350	24,509	24.3%	8.3%
Transportation	1,281	1,130	2,344	13.4%	-45.3%
General and administrative	5,763	2,553	5,988	125.7%	-3.8%
Interest - cash	8,916	17,746	26,749	-49.8%	-66.7%
Net income					
Net income (loss) from continuing operations, after tax	\$ (185,114)	\$ (24,839)	\$ (60,190)	645.3%	207.5%
Income (loss) from discontinued operations, after tax	-	(383)	489	N/A	-100.0%
Gain on sale of discontinued operations, after tax	(187)	74,441	-	-100.3%	N/A
Total income (loss) from discontinued operations, after tax	(187)	74,058	489	-100.3%	-138.2%
Net income (loss), after tax	\$ (185,301)	\$ 49,219	\$ (59,701)	-476.5%	210.4%

MANAGEMENT'S DISCUSSION AND ANALYSIS

During the fourth quarter of 2008, production at the Beta Unit continued to increase as additional wells were returned to production at Platform Eureka. Production of 3,404 boe/d was up 17.2% over the third quarter of 2008 and was double the production of the fourth quarter of 2007. Production in Alaska was 3,680 boe/d, down as result of mechanical failures certain of which cannot be repaired until summer 2009. Production in Alaska for the fourth quarter of 2008 was 18.4% lower than for the third quarter of 2008 and 17.6% below the fourth quarter of 2007.

Our average realized price received was \$51 per barrel of oil in the fourth quarter of 2008, down 53.8% compared to the third quarter of 2008 and down 38.8% from the fourth quarter of 2007. The average realized price after hedging losses for the fourth quarter of 2008 was \$55, down 35.1% and 15.6% from the third quarter of 2008 and the fourth quarter of 2007, respectively.

The net result was revenue after hedging gain of \$38.7 million for the fourth quarter of 2008, down 24.4% from the third quarter of 2008 but up 9.2% compared to the year ago period.

Lease operating expenses were \$40 per barrel for the fourth quarter of 2008, with the Beta Unit at \$24 per boe (down 15.1% and 37.7% from the comparative quarters) and Alaska at \$55 per boe (up 36.1% and 46.4% from the comparative quarters). The Beta Unit's LOE per boe decreased with higher volumes and reduce costs. Alaskan LOE per boe increased as a result of lower production and, in the case of the properties operated by Chevron, higher spending on maintenance projects.

G&A expense was up from \$2.6 million for the third quarter of 2008 to \$5.8 million for the fourth quarter of 2008 due to legal fees for the Forbearance Agreements and restructuring costs including outside consultants and advisors.

Cash-based interest expense was down for the fourth quarter of 2008 compared to the third quarter of 2008 due to the capitalization of approximately \$17.8 million of accrued interest to principal. We also accrued in the fourth quarter of 2008 a "conversion fee" of \$10.7 million payable February 24, 2009 on the expected balance of outstanding loans under the Alaska credit facilities.

We recorded an impairment charge of \$131.4 million. Included in the impairment is \$126.1 million related to certain Alaska petroleum and natural gas properties' net book value exceeding fair value. We also recorded impairment of unproved properties of \$0.3 million related to the expiration of certain exploration leases. In addition, we recorded a write down of oil inventories of \$5.3 million, as the market value of oil inventory was lower than its carrying value at December 31, 2008.

All other fourth quarter events were in line with our normal course of business.

The net loss from continuing operations for the fourth quarter of 2008 was \$185.1 million compared to \$24.8 million for the third quarter of 2008 and \$60.2 million for the fourth quarter of 2007.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Debt

Description	(dollar amounts are in thousands)	
	12/31/2008	12/31/2007
Goldman Sachs and Silver Point Financial		
Beta senior secured	\$ 33,138	\$ 65,000
Alaska first lien	111,274	108,000
Alaska second lien	323,060	285,269
Goldman Sachs and Silver Point Financial	467,472	458,269
Forest zero coupon note	33,253	29,976
Unsecured shareholder loan	1,000	-
Total face value of debt	501,725	488,245
Unamortized discounts	-	(27,097)
Unamortized debt issue costs	-	(27,277)
Book value of debt	501,725	433,871
Current portion of long term debt	(468,472)	-
Long term portion of note payable	\$ 33,253	\$ 433,871

The change in our total debt outstanding as at December 31, 2008 shows a net increase from the year ago period of \$13.5 million in face value. Debt was reduced \$45 million in July 2008 from a portion of the proceeds from the July onshore California asset sales (not including \$18 million repaid in discontinued operations). More than offsetting this reduction was approximately \$13 million in additional loans pursuant to the SSC Credit Facility and \$41 million in paid in kind interest and accrued interest that was converted into principal. Additionally there was an approximately \$3 million increase due to the accretion of the Forest Oil note and a \$1 million unsecured loan for general working capital use that did not exist at December 31, 2007.

Forbearance Agreements

On December 19, 2008, we entered into forbearance and amendment agreements (collectively, as further amended in January and February 2009, the "Forbearance Agreements") to each of our secured credit facilities (see "*SSC Facility*" and "*Alaska Facility*" in our AIF for further details regarding these facilities). Pursuant to the Forbearance Agreements, we revised various terms of these secured credit facilities, and the lenders and hedge provider agreed to forbear temporarily from exercising their rights and remedies against us and our subsidiaries with respect to certain specified existing and anticipated defaults under the credit facilities and hedge agreements, subject to certain conditions.

The Forbearance Agreements included a commitment for \$19.5 million in additional funding under the SSC Credit Facility. We agreed to pay a 1.0% fee on the unused portion.

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In connection with the Forbearance Agreements, we agreed to a number of additional covenants, including the requirement to prepare and comply with an interim forbearance budget.

The forbearance period expired February 17, 2009, at which time we were out of compliance with a variety of the affirmative and negative covenants under the SSC Credit Facility and the Alaska credit facilities (also described below). Being unable to reach agreement with the secured lenders to further extend the forbearance period or revise the SSC Credit Facility and the Alaska credit facilities, we filed for bankruptcy protection on March 9, 2009 and entered into the DIP Facility described in "Insolvency Proceedings" above and "DIP Financing" below.

On March 11, 2009, we paid an aggregate of \$44.2 million (including interest, unpaid expenses and a \$3.8 million make-whole payment) to the lenders using funds obtained under the DIP Facility, and the SSC Credit Facility was terminated. The SSC Credit Facility would otherwise have matured November 29, 2010, but given the existence of various defaults, the lenders had the right to accelerate the maturity date and exercise other remedies under the SSC Credit Facility. The prepayment penalty (make-whole payment) resulted from the repayment of the SSC Credit Facility prior to November 30, 2009 and was in an amount equal to the unpaid scheduled interest payments on the prepaid principal amounts calculated through November 30, 2009.

On March 11, 2009, we paid an aggregate of \$98.4 million (including accrued but unpaid interest and a \$2.7 million conversion fee on the first lien credit agreement) to the lenders using funds obtained under the DIP Facility, and the Alaska first lien credit facility was terminated. Immediately prior to this termination, certain Alaska oil sales hedging contracts were terminated and together with cash on hand, \$15.9 million of the Alaska first lien loan was repaid.

The Alaska second lien credit facility remains outstanding and continues to accrue interest at the default rate. As of March 20, 2009, we were out of compliance with a variety of the Alaska second lien credit agreement's affirmative and negative covenants. The lenders have not granted a formal waiver or amendment of the terms of the Alaska second lien credit agreement. However, the lenders are parties to the DIP Facility, consented to the priming of their liens existing under the Alaska second lien credit agreement and related documents, and are subject to the initial automatic stay issued by the Bankruptcy Court.

DIP Financing

We entered into a DIP financing pursuant to a \$186.6 million Senior Secured Super Priority Priming Debtor in Possession Credit and Guaranty Agreement ("DIP Facility") with an entity affiliated with The Goldman Sachs Group, Inc. and five entities affiliated with Silver Point Finance, LLC. Under the DIP Facility, we and two of our wholly-owned subsidiaries, Pacific Energy Alaska Operating LLC ("PEAO") and Pacific Energy Alaska Holdings, LLC ("PEAH") are borrowers, and we and all of our wholly-owned subsidiaries are guarantors. The DIP Facility is secured by a superpriority lien on substantially all of our assets and a pledge of all the issued and outstanding capital stock of each of our wholly-owned subsidiaries, which lien is junior only to certain permitted prior liens.

The DIP Facility includes an initial \$3.0 million funded on March 11, 2009 and up to an additional \$41.0 million that may also be funded under a new revolving facility ("Revolving

MANAGEMENT'S DISCUSSION AND ANALYSIS

Facility”), plus refinancing through two new short-term loans of \$44.2 million (“PERL Term Facility”) and \$98.4 million (“PEAO Term Facility”) covering the remaining obligations that were outstanding under the SSC Credit Facility and the Alaska first lien credit facility, which credit facilities were terminated upon entry into the DIP Facility. The Alaska second lien credit facility entered into on August 27, 2007 remains outstanding, with a balance on March 8, 2009, of approximately \$347.3 million.

The maturity date of the DIP Facility is the earliest to occur of (i) September 10, 2009, (ii) the effective date of the borrowers’ reorganization plan, (iii) the date on which the borrowers have consummated a sale or sales of substantially all of the borrowers’ assets pursuant to Bankruptcy Court and lender approval, and (iv) the date of termination of the lenders’ obligations to make loans or permit existing loans to remain outstanding pursuant to the event of default provisions of the DIP Facility.

Non-default interest on outstanding advances under the DIP Facility accrues at an annual rate equal to 10.5% plus the greater of 4.0% and the adjusted Eurodollar rate, computed on the basis of a 360-day year for the actual number of days elapsed. A portion of the interest on each loan accrues at an annual rate equal to 4.0% and is payable in cash on each monthly payment date. The remaining portion of interest on each loan is to be compounded into the outstanding principal amount of the loans on each monthly payment date. The interest rate is increased by an additional 2.0% upon the occurrence and during the continuance of an event of default as defined in the DIP Facility.

The DIP Facility requires a lockbox mechanism whereby all of the cash revenues and cash receipts of ours and of our wholly-owned subsidiaries are swept daily into two collateral accounts – one account for PEAO and PEAH (“PEAO Collateral Account”) controlled by Silver Point Finance, LLC as collateral agent and the other account for us and our wholly-owned subsidiaries other than PEAO and PEAH (“PERL Collateral Account”) controlled by an affiliate of The Goldman Sachs Group, Inc. as collateral agent. The borrowers request permission from the collateral agents to pay expenses in accordance with the budget established under the DIP Facility.

All good collected amounts in excess of \$250,000 or such greater amount as may be determined from time to time by the holders of 66-2/3% of the loan exposure under the DIP Facility (“Required Lenders”) (after accounting for outstanding checks) are applied by the collateral agents to prepay the principal outstanding on the loans under the DIP Facility on the first business day of each week as follows:

- each prepayment made by the collateral agent from the PEAO Collateral Account is applied first to prepay the Revolving Facility; second to prepay the PEAO Term Facility; third to prepay obligations under the Alaska second lien credit agreement; and fourth to prepay the PERL Term Facility; and
- each prepayment made by the collateral agent from the PERL Collateral Account is applied first to prepay the Revolving Facility; second to prepay the PERL Term Facility; third to prepay obligations under the Alaska second lien credit agreement; and fourth to prepay the PEAO Term Facility.

MANAGEMENT'S DISCUSSION AND ANALYSIS

In addition to the prepayments to be effectuated by the collateral agents, we are required to make prepayments with the proceeds of any non-ordinary course sales of collateral and the proceeds of casualty or property insurance. We may make voluntary prepayments without premium or penalty in increments of at least \$1.0 million in principal amount plus interest.

The DIP Facility contains customary events of default, representations, warranties and covenants for a loan of this type, as well as the following covenants:

- use of proceeds from the DIP Facility and use of other cash from other sources is limited to permitted purposes and amounts approved by the Required Lenders, as described in the budget required to be filed with the Bankruptcy Court;
- we were required to assume the pre-petition oil and gas production hedging contract with an affiliate of The Goldman Sachs Group, Inc. relating to our Beta Unit operations and are prohibited from entering into other hedging contracts;
- we are prohibited, subject to certain limited exceptions, from forming or acquiring additional subsidiaries or business entities, merging or consolidating with or into other business entities, selling assets or properties outside the ordinary course of business, and issuing additional capital stock or securities convertible into or exercisable for capital stock (other than upon conversion or exercise of outstanding derivative securities);
- we are prohibited from incurring additional indebtedness or liens, except for certain limited permitted indebtedness and liens;
- we are required to engage various professionals, including a chief restructuring officer, investment banker and business broker, and provide numerous reports, financial statements and other information to the lenders, administrative agent and hedge provider;
- we are prohibited from allowing the aggregate volume of production to vary more than a certain percentage from the amount shown in our budget or as otherwise agreed to by the Required Lenders; and
- we are prohibited from paying any expenses or disbursements other than those set forth in our budget, plus a permitted percentage variance on budgeted expenses or disbursements.

MANAGEMENT'S DISCUSSION AND ANALYSIS

In addition to interest on the outstanding advances under the DIP Facility, each lender will receive its proportionate share of:

- a commitment fee equal to 0.75% times the actual daily amount by which the aggregate commitments under the DIP Facility exceed the sum of the outstanding amount of all loans under the DIP Facility, which is due and payable monthly in arrears on the last business day of each month, commencing March 31, 2009, and on the maturity date; and
- a facility payment equal to \$1.0 million, which accrues interest at the effective interest rate under the DIP Facility from March 11, 2009 through the maturity date, and is due and payable to the administrative agent on the maturity date unless the borrowers elect to make the facility payment earlier.

Unsecured Shareholder Loan

We received a \$1.0 million unsecured loan from Bateman and Co. ("Bateman") on April 4, 2008 for use as working capital. The promissory note evidencing the loan had an interest rate of 9% per annum, and the principal with interest was to be due five days after demand for payment. We, in our sole discretion, had the right to pay the outstanding principal and interest at any time whether or not a demand for payment had occurred. On February 10, 2009, we and Bateman entered into a replacement note with a principal balance of \$1.03 million (reflecting the original principal amount of \$1.0 million plus accrued and unpaid interest) to (i) increase the interest rate to the London Interbank Offered Rate ("LIBOR") plus 18.5% per annum beginning February 1, 2009, such interest to be capitalized to the principal outstanding at the end of each calendar month, (ii) modify the maturity date to be the earlier of February 10, 2012 or 91 days after the repayment in full of the SSC Credit Facility and the Alaska credit facilities and (iii) to allow for, at Bateman's option, conversion of all or any portion of principal balance to shares of our common stock at a conversion price of \$0.073 per dollar being converted into common stock.

Cash & Cash Equivalents

As of March 24, 2009, we had a cash balance of approximately \$1.2 million. Each week, any excess funds above \$250,000 are swept to repay amounts outstanding under our DIP Financing.

In addition, at December 31, 2008, we had approximately \$106.2 million of cash securing abandonment obligations and a further \$5.8 million securing performance bonds. During 2008, we attempted to free up some of this bond money by accessing the surety markets with the goal of replacing a portion of the cash deposits with surety bonds but were unable to do so.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Capital Structure

The Insolvency Proceedings described above have significantly affected our ability to manage our capital structure in the near term. The DIP Financing, combined with our operating revenue, are intended to provide sufficient liquidity to fund working capital, meet ongoing obligations and ensure that normal operations continue without interruption during our reorganization.

Sensitivities

Due to the volatility of commodity prices, we are potentially exposed to adverse consequences in the event of declining prices. With the consent of our lenders, we may enter into oil and natural gas contracts in order to protect our cash flow on future sales. The contracts reduce the fluctuation in sales revenue by locking in prices with respect to future deliveries of oil and natural gas.

Based on annualizing fourth quarter our 2008 production levels, a \$10 per barrel change in oil prices would change revenue net of royalties (after factoring in our hedge position as of December 31, 2008) by approximately \$7.8 million per year.

Our credit facilities are subject to floating rates and we are, therefore, exposed to fluctuations in the market rate of interest. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates.

Until LIBOR reaches 4.0%, a fluctuation in interest rates of 1.0% would have no effect on interest expense based on our outstanding floating rate debt as of December 31, 2008. Once LIBOR exceeds 4.0%, a fluctuation in interest rates of 1.0% would change interest expense by \$0.6 million per year based on our outstanding floating rate debt as of December 31, 2008.

Future Dividends

We have not declared or paid any cash dividends on our capital stock in the past, and we do not anticipate declaring or paying cash dividends on our common stock in the foreseeable future. In addition, our credit facilities prohibit the payment of dividends without lender consent.

We will pay dividends on our common stock only if and when declared by our board. Our board's ability to declare a dividend is subject to restrictions imposed by Delaware law. In determining whether to declare dividends, our board will consider these restrictions as well as our financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant. Obviously, the payment of dividends is not feasible during this period of restructuring.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Off-Balance Sheet Arrangements

We have entered into crude oil hedging contracts which are discussed below in the "Financial and Other Instruments" section in more detail.

Related Party Transactions

Transactions with related parties are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

- At December 31, 2008 and December 31, 2007, we owed \$76,000 and \$61,000, respectively, to a related party for amounts incurred by the related party on our behalf. These amounts are non-interest bearing and due on normal trade terms. The transactions were to purchase maintenance parts from the an inventory of the related party.
- During the year ended December 31, 2007, we incurred legal costs of \$385,000 with a law firm owned in part, until October 31, 2007, by one of our directors. A balance of approximately \$22,000 was owed at December 31, 2007. We use that law firm for our Canadian securities work.

We have no ongoing obligations to any related party.

Changes in Accounting Policy

- Effective January 1, 2008, we adopted CICA Handbook Section 3031 – Inventories which replaced corresponding Section 3030 and established new standards for the measurement and disclosure of inventories. The new Section prescribes that inventories should be measured at the lower of cost and net realizable value and provides guidance on the determination of cost. The adoption of this standard did not have a material impact on our consolidated financial statements.
- We will adopt the new standard CICA 3064, Goodwill and Intangible Assets for its fiscal year beginning January 1, 2009. This Section replaces CICA 3062, Goodwill and Intangible Assets and CICA 3450 Research and Development Costs. The new Section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in CICA 3062. We do not anticipate that the adoption of the new Section will have a material effect on our financial statements.
- We adopted EIC 172, which requires the recognition of previously unrecognized tax loss carry forwards consequent to the recording of unrealized gains in other comprehensive income. This had no effect on our financial statements.
- We adopted CICA 1535, for capital disclosures. This section established standards for disclosing information about an entity's capital and how it is managed.

MANAGEMENT'S DISCUSSION AND ANALYSIS

- We adopted CICA 3862 and 3863, for financial instrument disclosures. The new disclosure standard expands our disclosure regarding the nature and extent of the risks associated with financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements.
- In January 2006, the Canadian Accounting Standards Board (“AcSB”) published a new strategic plan that will significantly affect financial reporting requirements for companies that report using Canadian GAAP. The AcSB strategic plan outlines the convergence of Canadian GAAP with International Financial Reporting Standards (“IFRS”) over a five-year transitional period. In February 2008, the AcSB announced that 2011 is the changeover date for publicly-accountable enterprises to use IFRS. The date is for interim and annual financial statement relating to fiscal years beginning on or after January 1, 2011. For us, the transition date will be effective January 1, 2011 and will require the restatement for comparative purposes of amounts we report for the year ending December 31, 2010. A detailed analysis of the difference between IFRS and our accounting policies, as well as an assessment of the impact of various alternatives, is to be conducted in 2009. Changes in accounting policies are likely and may materially impact our consolidated financial statements.

None of these accounting policy changes have had or are expected to have a material impact on our financial condition.

Critical Accounting Estimates

The MD&A is based on our consolidated financial statements which have been prepared in US dollars in accordance with Canadian GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, as well as the reported amount of revenues and expenses during the reporting period. Actual results will likely differ from those estimates. Our critical accounting estimates are described below and are discussed with the Audit Committee of the Board of Directors of the Company each year.

Successful Efforts Method of Accounting

Under the successful efforts method of accounting, we capitalize only those costs that result directly in the discovery of petroleum and natural gas reserves, including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures includes geological and geophysical costs, lease rentals and exploratory dry holes are charged to earnings in the period incurred. The application of the successful efforts method of accounting requires management’s judgment to determine the proper designation of wells as either developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze and the determination that proved reserves have been discovered requires both judgment and the application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management’s judgment to evaluate the fair value of land in a given area.

Purchase Price Allocations

We made significant acquisitions in 2007, and the resulting purchase price allocations are a critical accounting estimate. We account for acquisitions by the purchase method of accounting whereby the purchase price is allocated to the assets and liabilities acquired based on their fair values at the time of acquisition. In order to estimate fair values, management has to make various assumptions including oil and natural gas prices, reserves acquired and discount rates. The resulting book values of assets and liabilities impact future periods' results through depreciation, depletion and amortization expense, and through periodic reassessment of those liabilities. In our case, the critical liability estimates were the amount of future asset retirement obligations (discussed below).

Reserve Estimates

Estimates of our petroleum and natural gas reserves are prepared by independent engineering firms in accordance with guidelines established by the Canadian Securities Administrators. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate. Reserves prepared by other engineering firms may be different than those prepared for the firms we engaged. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. The reported value of future net revenues should not be assumed to be the current market value of our estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. The estimates of reserves impact depletion, dry hole expenses and asset retirement obligations. If reserve estimates decline, the rate at which we record depletion increases thereby reducing net earnings. In addition, changes in reserve estimates may impact the outcome of our assessment of petroleum and natural gas properties for impairment. Changes in reserve estimates could affect the Company's liquidity to the extent availability under our credit facilities is based on reserves. Our DIP Facility has no such feature. Our prior credit agreements contained asset coverage ratios (ratios of indebtedness to reserve discounted net revenue amounts) as financial covenants.

Impairment of Petroleum and Natural Gas Properties and Equipment

We review our proved properties for impairment on a field basis. For each property, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of that property may not be recoverable. The impairment charge is based on the excess of carrying value over fair value. Fair value is defined as the present value of the future net revenues from the property as estimated on the balance sheet date. Reserve estimates and estimates for petroleum and natural gas prices and production costs may change and there can be no assurance that impairment provisions will not be required in the future. Impairment charges

MANAGEMENT'S DISCUSSION AND ANALYSIS

for the year ended December 31, 2008 of \$131.4 included \$126.1 million of impairment for certain of our Alaskan properties.

Asset Retirement Obligations

Asset retirement obligations recorded in the consolidated financial statements are an estimate of the fair value of the total future site restoration and abandonment of our petroleum and natural gas properties and equipment. This estimate is based on engineering estimates. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments. The amounts estimated are accreted in future periods until those monies are spent. These estimates are revised annually. The asset retirement obligations are accreted over time to the estimated year of expenditure. The book value of these obligations was \$60.8 million at December 31, 2008.

Financial and Other Instruments

Our financial assets and liabilities consist of cash, accounts receivable, accounts payable, notes payable and accrued liabilities. We have placed our cash and cash equivalents in liquid bank deposits. In addition, to date we have funded our bonding obligations by placing cash in restricted accounts and securing the obligation for 100% of the estimated bonding amount. We have approximately \$106.2 million in fully-funded abandonment funds. The instruments used to secure these obligations are principally Treasury Notes and money market funds.

Due to the historical volatility of crude oil prices, as well as credit agreement requirements, we had a hedging strategy aimed at reducing the variability of the prices we receive on our production and provide a calculable minimum revenue stream. Concurrent with the signing of the Forbearance Agreements, on December 19, 2008 we restructured our hedge position to create an additional opportunity to benefit from potentially higher oil prices in the coming year, while preserving protection against low oil prices during 2009. We established offsetting swaps for our existing Beta Unit crude oil fixed price forward sales, effectively terminating them at a profit and leaving Beta Unit production unhedged, and replaced our Alaska crude oil fixed price forward sales for the period December 2008 through September 2012 with in-the-money put options through 2009. Our then hedge position consisted of put options for 2,500 barrels per day at a strike price of \$67 per barrel for the period December 2008 through December 2009. On March 6, 2009, the Alaska put options were terminated by the hedge provider in accordance with the default provisions of the hedge agreement. Our proceeds were \$13.7 million, which were applied to reduce the Alaska first lien loan balance. We assumed post-petition our existing Beta hedges in connection with the DIP Facility.

The risks involved in such contracts are several. We enter into such contracts only with what we believe to be credit-worthy counterparties. We hedge only a fraction of our production, up to about 75-80% of our expected production from "proved, developed, producing" properties. To date, we have been able to hedge crude oil sales against the price index we receive for our physical sales. Due to our loans being in default, our lenders required us to terminate hedges in July 2008 and March 2009 when we otherwise would not have done so. Our board of directors monitors our use of crude oil hedging contracts, and will, in the future, develop formal risk management policies.

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Accounting for derivative instruments is described in Note 2 to our consolidated financial statements for the year ended December 31, 2008.

Outstanding Share, Warrants and Option Data

	(numbers are in thousands)		
	Number of Shares	Number of Warrants	Number of Options
Balance at December 31, 2006	77,599	37,723	5,160
Options granted	-	-	7,068
Options forfeited	-	-	(195)
Warrants issued	-	53,804	-
Warrants exercised	2,068	(2,068)	-
Shares issued for acquisitions	10,000	-	-
Shares issued for debt	4,750	-	-
Shares issued for deferred financing costs	3,097	-	-
Shares issued for liquidated damages	648	-	-
Stock options exercised	31	-	(31)
Common stock issued	88,450	-	-
Balance at December 31, 2007	186,643	89,459	12,002
Options granted	-	-	9,042
Options expired	-	-	(100)
Options forfeited	-	-	(878)
Warrants issued	-	12,516	-
Warrants expired	-	(790)	-
Warrants exercised	12,171	(12,171)	-
Shares issued for deferred financing costs	2,063	-	-
Shares issued for liquidated damages	4,592	-	-
Balance at December 31, 2008	205,469	89,014	20,066
Options granted	-	-	35
Options expired	-	-	(150)
Options forfeited	-	-	(1,089)
Warrants expired	-	(2,799)	-
Balance at March 20, 2009	205,469	86,215	18,862
Exercise Price (Canadian dollars)		\$1.40 to \$2.65	\$0.15 to \$3.00

	(numbers are in thousands)	
	For the Year Ended December 31,	
	2008	2007
Basic Weighted Average Shares Outstanding	203,697	140,632
Diluted Weighted Average Shares Outstanding	314,549	297,150

In addition, an unsecured loan is convertible into 14.1 million shares as of March 9, 2009. Total fully diluted shares as of this date are 324.7 million.

All warrants exercised during 2008 were exercised during the first quarter. No warrants have been exercised in 2009.

As a result of the DIP Financing, the SSC Credit Facility has been terminated. As such,

MANAGEMENT'S DISCUSSION AND ANALYSIS

the unvested portion of the lender warrants associated with the SSC Credit Facility have been terminated as of March 11, 2009, and some other warrants have also lapsed. The total number of warrants terminated represents approximately 2.8 million shares.

We estimate that through March 11, 2009, the anti-dilution provisions of certain warrant required adjustments to increase the aggregate number of shares underlying the lender warrants by approximately 1.4 million shares and to decrease the exercise price of the lender warrants to approximately CAD\$1.344 per share. Through December 31, 2008, the adjustment amount was 0.3 million shares. However, these adjustments have not been made as these adjustments are subject to stock exchange approval that has not been applied for or obtained in light of the pending delisting of the Company's common stock from the TSX stock exchange. Due to the insolvency proceedings that the Company entered into on March 9, 2009, it is unlikely that the above warrants will be issued.

Selected Quarterly Information

The following tables show revenue and income data of the most recent eight quarters:

(dollar amounts are in thousands)

	For the Three Months Ended			
	Dec. 31, 2008	Sept. 30, 2008	June 30, 2008	March 31, 2008
Total Oil & Gas Revenue	\$ 36,480	\$ 67,340	\$ 69,721	\$ 52,704
Net Loss	\$ (185,114)	\$ (24,839)	\$ (24,906)	\$ (88,743)
Net Loss per share (basic)	\$ (0.91)	\$ (0.12)	\$ (0.12)	\$ (0.44)

Note: Each period includes discontinued operations

	For the Three Months Ended			
	Dec. 31, 2007	Sept. 30, 2007	June 30, 2007	March 31, 2007
Total Oil & Gas Revenue	\$ 45,250	\$ 26,064	\$ 9,660	\$ 3,283
Net Loss	\$ (60,190)	\$ (18,865)	\$ (9,273)	\$ (5,716)
Net Loss per share (basic)	\$ (0.43)	\$ (0.13)	\$ (0.08)	\$ (0.06)

Note: Each period includes discontinued operations

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Selected Annual Information from Continuing Operations

	For the Year Ended		
	December 31,		
	2008	2007	2006
Total revenue	\$ 226,245	\$ 84,257	\$ -
Net loss from continuing operations, after tax	\$ (323,602)	\$ (94,040)	\$ (16,981)
Income (loss) from discontinued operations, after tax	(8,260)	(4,709)	4,958
Gain on sale of discontinued operations, after tax	74,254	-	-
Total income (loss) from discontinued operations, after tax	65,994	(4,709)	-
Net loss, after tax	\$ (257,608)	\$ (98,749)	\$ (12,023)
Basic and diluted loss per share from continuing operations	\$ (1.59)	\$ (0.67)	\$ (3.60)
Basic income (loss) per share from discontinued operations	0.32	(0.03)	3.80
Diluted income (loss) per share from discontinued operations	0.21	(0.03)	3.80
Basic and diluted loss per share	(1.27)	(0.70)	0.20
Total assets	\$ 536,370	\$ 691,871	\$ -
Total financial liabilities ⁽¹⁾	\$ 511,698	\$ 32,657	\$ -
Long-term notes payable	\$ 33,253	\$ 433,871	\$ 25,294

⁽¹⁾ Includes accounts payable and accrued liabilities, due to related parties, current portion of notes payable, and other current liabilities.

The Company has net operating loss ("NOL") carryforwards at December 31, 2008 in the amount of \$203.9 million in Federal NOL and \$205.4 million in State NOL. The Company has received an interim order from the bankruptcy court to restrict trading in our common shares, in an effort to protect the Company from being subject to change of control tax rules from applying such that the NOLs become restricted. However, there is no assurance that such NOL will not be restricted.

Subsequent Events

All subsequent events have been fully described in the text above and the accompanying notes to the audited financial statements. The subsequent events include "Insolvency Proceedings", "DIP Financing", and termination of put options in "Financial and Other Instruments" and "Off-Balance Sheet Arrangements".

Business Risks & Risk Management

Except for historical information contained in this discussion and analysis, disclosure statements contained herein are forward-looking, which statements are subject to risks and uncertainties, which could cause actual results to differ materially from those in such forward-looking statements.

Based on our current operating condition, the following risks need to be outlined, as well as the risks referred to above in "Forward-Looking Statements":

- Risks related to our Insolvency Proceedings and the ultimate outcome of those

MANAGEMENT'S DISCUSSION AND ANALYSIS

proceedings;

- Risks related to our financial condition, including our dependence on the DIP Financing and lack of capital to replace natural declines in production;
- Risks related to our business, including fluctuating oil prices and cash operating losses at current oil prices; and
- Risks related to ownership of our common stock, including the current halt on trading in our shares on the TSX, the impact of the TSX announcement of delisting our shares and current restrictions on trading our stock to protect our net operating loss carryforwards.

These risks are more fully described in our Annual Information Form for the year ended December 31, 2008.

Future Prospects

We are required under the DIP Financing to pursue the sale of our assets. Concurrent with this process, we will be developing a plan of reorganization. Subject to Bankruptcy Court approval, we have engaged several advisors to assist with these processes. Prior to filing for chapter 11 protection, we engaged Scott Winn of Zolfo Cooper, LLC to be our Chief Restructuring Officer, reporting to our board of directors. We hired the investment banking firm Lazard Frères & Co. LLC to assist us in evaluating and executing on one or more strategic alternatives. Additionally, we hired Albrecht & Associates, Inc. to run the sales process for the Beta Unit. We cannot predict the outcome of these processes. See also "Economic Dependence and Going Concern" above.

We are dependent on the DIP Financing to cover our monthly cash shortfall (after sustaining capital expenditures) at the average oil price realized in the first quarter.

Internal Disclosure Controls

We place considerable diligence on the appropriate capture and reporting of financial information. We further recognize the need for timeliness with respect to management reporting to the appropriate internal personnel, including the Chief Executive Officer and the Chief Financial Officer among others, and the importance of effectively communicating relevant information to the investor community. With that in mind, we have designed internal controls specifically aimed at providing a reasonable level of assurance that material transactions are reported, accounted for properly, and effectively communicated to key decision makers within the organization.

While no internal control system will prevent intentional omissions or fraud, we believe we are designing a system appropriate for the current level of complexity we are managing. During the first three quarters of the 2008 fiscal year, we augmented several of our internal disclosure controls and internal control over financial reporting. Some of these improvements included expanding documentation and review processes and the hiring of additional accounting staff with the requisite knowledge.

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The control framework used to design and evaluate the Company's internal controls over financial reporting is the *Internal Control – Integrated Framework* (COSO Framework).

At this time, we conclude that our internal controls (including controls over financial reporting and disclosure controls and procedures) contain a material control weakness. There is potential for incomplete or inadequate accounting or disclosure due to an insufficient amount of accounting staff, including those with a sufficient knowledge of Canadian GAAP. This material weakness has the potential to impact our ability to properly account for and report complex transactions or significant estimates or otherwise comply with Canadian GAAP. In light of our current restructuring, we do not plan on addressing this material control weakness at this time, except to utilize third-party resources to assist us.

No changes have been made in our internal control over financial reporting during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to affect such controls.

In accordance with Multilateral Instrument 52-109, our Chief Executive and Chief Financial Officers are required to sign individual Certifications of the Annual Filings. These restated certificates have been filed separately from the Management's Discussion and Analysis and are available for viewing on SEDAR.com.