

# InterOil Corporation Management Discussion and Analysis

For the Year ended December 31, 2009  
March 1, 2010



## TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS .....	2
OIL AND GAS DISCLOSURES.....	3
INTRODUCTION .....	4
BUSINESS STRATEGY.....	4
OPERATIONAL HIGHLIGHTS.....	5
SELECTED ANNUAL FINANCIAL INFORMATION AND HIGHLIGHTS .....	7
YEAR AND QUARTER IN REVIEW.....	12
LIQUIDITY AND CAPITAL RESOURCES.....	19
INDUSTRY TRENDS AND KEY EVENTS .....	26
RISK FACTORS .....	29
CRITICAL ACCOUNTING ESTIMATES.....	29
NEW ACCOUNTING STANDARDS.....	31
NON-GAAP MEASURES AND RECONCILIATION .....	32
PUBLIC SECURITIES FILINGS.....	34
DISCLOSURE CONTROLS AND PROCEDURES.....	34
GLOSSARY OF TERMS.....	35

The following Management Discussion and Analysis (“MD&A”) should be read in conjunction with our audited consolidated financial statements and accompanying notes for the year ended December 31, 2009 and annual information form for the year ended December 31, 2009 (the “2009 Annual Information Form”). The MD&A was prepared by management and provides a review of our performance in the year ended December 31, 2009, and of our financial condition and future prospects.

Our financial statements and the financial information contained in this MD&A have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and are presented in United States dollars (“USD”) unless otherwise specified. References to “we,” “us,” “our,” “Company,” and “InterOil” refer to InterOil Corporation and/or InterOil Corporation and its subsidiaries as the context requires. Information presented in this MD&A is as at and for the year ended December 31, 2009, unless otherwise specified.

We are not presenting all the U.S. GAAP information in this MD&A. Readers should review note 30 - “Reconciliation to the generally accepted accounting principles in the United States” to the audited financial statements for the year ended December 31, 2009 for the reconciliation of the Canadian GAAP and U.S. GAAP information.

## FORWARD-LOOKING STATEMENTS

---

This MD&A contains “forward-looking statements” as defined in U.S. federal and Canadian securities laws. Such statements are generally identifiable by the terminology used such as “may,” “plans,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “forecasts,” “budgets,” “targets” or other similar wording suggesting future outcomes or statements regarding an outlook. We have based these forward-looking statements on our current expectations and projections about future events. All statements, other than statements of historical fact, included in or incorporated by reference in this MD&A are forward-looking statements. Forward-looking statements include, without limitation; plans for our exploration (including drilling plans) and other business activities and results therefrom; the construction of an LNG plant and condensate stripping facility in Papua New Guinea; the development of such LNG plant and stripping facility; the commercialization and monetization of any resources; whether sufficient resources will be established; the likelihood of successful exploration for gas and gas condensate; the potential discovery of any commercial quantities of oil; cash flows from operations; sources of capital; operating costs; business strategy; contingent liabilities; environmental matters; and plans and objectives for future operations; the timing, maturity and amount of future capital and other expenditures.

Many risks and uncertainties may affect the matters addressed in these forward-looking statements, including but not limited to:

- *our ability to finance the development of an LNG and condensate stripping facility;*
- *the uncertainty in our ability to attract capital;*
- *the uncertainty associated with the regulated prices at which our products may be sold;*
- *the inherent uncertainty of oil and gas exploration activities;*
- *potential effects from oil and gas price declines ;*
- *the availability of crude feedstock at economic rates;*
- *our ability to timely construct and commission our LNG and condensate stripping facility;*
- *difficulties with the recruitment and retention of qualified personnel;*
- *losses from our hedging activities;*
- *fluctuations in currency exchange rates;*
- *the uncertainty of success in pending lawsuits and other proceedings;*
- *political, legal and economic risks in Papua New Guinea;*
- *our ability to meet maturing indebtedness;*
- *stock price volatility;*
- *landowner claims and disruption;*
- *compliance with and changes in foreign governmental laws and regulations, including environmental laws;*
- *the inability of our refinery to operate at full capacity;*
- *the impact of competition;*
- *the margins for our products;*
- *inherent limitations in all control systems, and misstatements due to errors that may occur and not be detected;*
- *exposure to certain uninsured risks stemming from our operations;*
- *contractual defaults.*
- *payments from exploration partners;*
- *interest rate risk;*
- *weather conditions and unforeseen operating hazards;*
- *the impact of legislation regulating emissions of greenhouse gases on current and potential markets for our products;*
- *the impact of our current debt on our ability to obtain further financing;*
- *the adverse effects from importation of competing products contrary to our legal rights; and*
- *law enforcement difficulties.*

Forward-looking statements and information are based on our current beliefs as well as assumptions made by, and information currently available to, us concerning anticipated financial conditions and performance, business prospects, strategies, regulatory developments, the ability to attract joint venture partners, future hydrocarbon

commodity prices, the ability to obtain equipment in a timely manner to carry out development activities, the ability to market products successfully to current and new customers, the effects from increasing competition, the ability to obtain financing on acceptable terms, and the ability to develop reserves and production through development and exploration activities. Although we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements will eventuate. In light of the significant uncertainties inherent in our forward-looking statements, the inclusion of such information should not be regarded as a representation by us or any other person that our objectives and plans will be achieved. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described under the heading "Risk Factors" in our 2009 Annual Information Form.

Furthermore, the forward-looking information contained in this MD&A is made as of the date hereof, unless otherwise specified and, except as required by applicable law, we will not update publicly or revise any of this forward-looking information. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

## **OIL AND GAS DISCLOSURES**

---

We are required to comply with Canadian Securities Administrators' National Instrument 51-101 Standards for Disclosure of Oil and Gas Activities ("NI 51-101"), which prescribes disclosure of oil and gas reserves and resources. GLJ Petroleum Consultants Ltd., an independent qualified reserve evaluator based in Calgary, Canada, has evaluated our resources data as at December 31, 2009 in accordance with NI 51-101 and is summarized in our 2009 Annual Information Form available at [www.sedar.com](http://www.sedar.com). We do not have any reserves, including proved reserves, as defined under NI 51-101, as per the guidelines set by the United States Securities and Exchange Commission ("SEC") under ASC Topic 932, as at December 31, 2009.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, possible and probable reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We include in this MD&A information that the SEC's guidelines generally prohibit U.S registrants from including in filings with the SEC. Investors are urged to consider closely the disclosure in the Company's Form 40-F dated March 1, 2010, available at [www.sec.gov](http://www.sec.gov).

All calculations converting natural gas to crude oil equivalent have been made using a ratio of six mcf of natural gas to one barrel of crude equivalent. Barrels of oil equivalent may be misleading, particularly if used in isolation. A barrel of oil equivalent conversion ratio of six mcf of natural gas to one barrel of crude oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## INTRODUCTION

---

We are developing a vertically integrated energy company in Papua New Guinea and the surrounding region. Our operations are organized into four major segments:

Segments	Operations
<b>Upstream</b>	<b>Exploration and Production</b> – Explores for and appraises potential natural gas and oil structures in Papua New Guinea with a view to commercializing significant discoveries. Current commercialization of the Elk and Antelope fields include the development of a proposed condensate stripping facility and development of gas production facilities for liquefied natural gas.
<b>Midstream</b>	<b>Refining</b> – Produces refined petroleum products at Napa Napa in Port Moresby, Papua New Guinea for the domestic market and for export. <b>Liquefaction</b> – Developing proposed onshore and/or offshore floating liquefied natural gas processing facilities in Papua New Guinea.
<b>Downstream</b>	<b>Wholesale and Retail Distribution</b> – Markets and distributes refined petroleum products domestically in Papua New Guinea on a wholesale and retail basis.
<b>Corporate</b>	<b>Corporate</b> – Provides support to the other business segments by engaging in business development and improvement activities and providing general and administrative services and management, undertakes financing and treasury activities, and is responsible for government and investor relations. General and administrative and integrated costs are recovered from business segments on an equitable basis. Our corporate segment results also include consolidation adjustments.

## BUSINESS STRATEGY

---

Our business strategy is to develop a vertically integrated energy company in Papua New Guinea and surrounding regions, focusing on niche market opportunities which provide financial rewards for our shareholders, while being environmentally responsible, providing a quality working environment and contributing positively to the communities in which InterOil operates. A significant element of that strategy is to establish and produce gas and condensate reserves and develop liquefaction and condensate stripping facilities in Papua New Guinea. The produced LNG would be exported overseas, whilst the condensate is planned to be used as feedstock for our Midstream - refinery.

InterOil plans to achieve this strategy by:

- Developing our position as a prudent and responsible business operator
- Enhancing the refining and distribution business
- Maximizing the value of our exploration assets
- Building an export liquefaction gas business
- Positioning ourselves for long term success

Further details of our business strategy can be found under the heading “*Business Strategy*” in our 2009 Annual Information Form available at [www.sedar.com](http://www.sedar.com).

## OPERATIONAL HIGHLIGHTS

---

### Summary of operational highlights

A summary of the key operational matters and events for the year, for each of the segments is as follows:

#### *Upstream*

- On March 2, 2009, the Antelope-1 well flowed gas at a rate equivalent to 382 million cubic feet of gas per day with 5,000 barrels of condensate per day. The well was drilled to a total depth of 8,892 feet (2,710 meters).
- On March 5, 2009, our PPL 238, 237 and 236 licenses were re-issued for a five year term.
- On April 17, 2009, an indirect participation interest ("IPI") investor waived conversion rights to 160,000 of our common shares under the IPI agreement triggering conveyance accounting for their 1.2% interest in the IPI program.
- On June 26, 2009, the Antelope-1 side track was completed with the installation of 2 7/8" tubing and the well was made ready for future production and/or long term flow testing.
- On July 27, 2009, the Antelope-2 well was spudded 2.3 miles to the south of Antelope-1. The purpose of this well was to help delineate the Antelope structure to the south and to further evaluate the condensate and oil observed in the Antelope-1 well.
- During August 2009, we applied for a Petroleum Retention Licence ("PRL") over the declared location. The declaration of location is a necessary pre-condition to the application for a PRL or a PDL. The declared location was granted to us in March 2009 on our discovery block, and an additional 8 blocks in the license that comprised the Elk and Antelope fields, and a development corridor. The PRL is yet to be granted.
- During September 2009, we bought back a total of 4.3364% of IPI interests held under the 2005 Amended and Restated Indirect Participation Agreement.
- During September 2009, we sold to Pacific LNG Operations Limited a 2.5% working interest in the Elk and Antelope fields under an option granted to it and announced by us on May 24, 2007. The interest was acquired in exchange for cash consideration totaling \$25.0 million, including \$15.0 million paid previously under the 2007 option, together with the transfer to us of 2.5% of Pacific LNG's economic interest in the LNG Project joint venture, and payment by Pacific LNG Operations Limited of certain historical costs incurred in exploring and developing these fields.
- On September 17, 2009, the Antelope-2 well intersected the top of the reservoir at 6,007 feet, 345 feet higher than pre-drill estimates.
- During the third quarter, CGG Veritas was mobilised in preparation to execute a planned 100km appraisal seismic program over the Elk and Antelope fields. This program progressed during fourth quarter and the first seismic lines were completed in December 2009.
- On December 1, 2009 a surface flow test conducted at Antelope-2 tested natural gas and condensate at a rate of 705 million cubic feet of gas per day with 11,200 barrels of condensate per day. Subsequent to the year end, the well was drilled to total depth of 8,087 feet (2,465 meters) with preparations now in place to drill a horizontal extension.
- During December 2009, we bought back a further 0.5% of indirect participation interests held under the 2005 Amended and Restated Indirect Participation Agreement.
- During December 2009, IPI investors with a 6.210% IPI interest waived their conversion rights to 828,000 of our common shares under the IPI agreement triggering conveyance accounting for their interest in the IPI program.
- During the fourth quarter we agreed to divest our 15% non operated interest in PPL244. The divestment remains subject to Papua New Guinea government approval, and contracted pre-emptive rights, and is expected to close in the first quarter of 2010.
- Subsequent to year end, on February 9, 2010, we announced the purchase of our second drilling rig, currently located in New Zealand, for approximately \$4.5 million.

#### *Midstream – Refining*

- Total refinery throughput during 2009 was 21,155 barrels per operating day, as compared with 22,034 barrels per operating day in 2008.

- Capacity utilization for the year, based on 36,500 barrels per day operating capacity, was 47% (44% for the fourth quarter of 2009) as compared to 44% in 2008 (57% in the same quarter of 2008).

#### *Midstream – Liquefaction*

- On February 27, 2009, InterOil LNG Holdings Inc. and Pacific LNG Operations Ltd., acquired Merrill Lynch's interest in the Joint Venture Company. As part of the acquisition all matters between the parties were settled such that Merrill Lynch retained no ongoing economic interests, legal rights or involvement in the LNG Project.
- During September 2009, we received a 2.5% economic interest in the LNG Project joint venture from Pacific LNG Operations Limited as part consideration for the sale of a 2.5% working interest in the Elk and Antelope fields under an option originally granted to it and announced by us on May 24, 2007.
- On December 23, 2009 the Government of Papua New Guinea signed the LNG Project Agreement ("Project Agreement") which sets the project fiscal terms for a twenty year period. It includes a 30% company tax rate and certain exemptions applicable to large scale projects of this nature. The Agreement also sets out the terms upon which the Government is able to acquire up to a 20.5% ownership interest in the Project, and for an additional 2% interest to be acquired by affected landowners.

#### *Downstream*

- Total Downstream sales volumes were 588.8 million liters in 2009, compared with 548.0 million liters in 2008.
- In March 2009 we entered into our first direct chartering shipping arrangement with the charter of Ipsilantis, a 3,645 dead weight tonnes ("DWT") vessel, which will result in us being able to direct vessel movements rather than co-ordinate shipping around Papua New Guinea with other distributors. The vessel is chartered for two years plus one optional year.
- In June 2009, the Papua New Guinea Independent Consumer and Competition Commission ("ICCC") commenced a review into the pricing arrangements for petroleum products in PNG. The last such review was undertaken during 2004 and was due to expire on December 31, 2009. The purpose of the review is to consider the extent to which the existing regulation of price setting arrangements at both wholesale and retail levels should continue, or be revised for the next five year period. We have provided detailed submissions to the ICCC. The ICCC have most recently advised that its final report will be issued in March 2010. It is possible that the ICCC may determine to increase regulation of pricing and reduce the margins able to be obtained by our distribution business. Such a decision, if made, may negatively affect our downstream business and require a review of its operations.
- Subsequent to year end, in January 2010, we have received delivery of our second charter vessel Saturn, a 13,051 DWT vessel. This vessel has been chartered for nine months with a further six months option to be called by us.

#### *Corporate*

- On January 27, 2009, the Company voluntarily delisted its common shares from the Toronto Stock Exchange.
- On March 31, 2009, our common shares commenced trading on the New York Stock Exchange and were delisted from the NYSE Alternext Stock Exchange (formerly the American Exchange), at the close of trading on March 31, 2009.
- During May and June 2009, remaining outstanding debentures from the May 2008 subordinated convertible debenture offering were converted into common shares.
- On June 8, 2009, we completed a registered direct stock offering of 2,013,815 common shares to a number of institutional investors at a purchase price of \$34.98 per share raising \$70.4 million
- During the quarter ended September 30, 2009, 302,305 of the 337,252 warrants outstanding were exercised and converted into common shares at an exercise price of \$21.91. All remaining unexercised warrants lapsed on August 27, 2009.
- During 2009 we reviewed and selected Microsoft Dynamics, a group wide Enterprise Resource Planning ("ERP") system for implementation across all streams. The implementation is expected to be completed by the third quarter of 2010.

## SELECTED ANNUAL FINANCIAL INFORMATION AND HIGHLIGHTS

**Consolidated Results for the year ended December 31, 2009 compared to year ended December 31, 2008 and 2007**

Consolidated – Operating results (\$ thousands, except per share data)	Year ended December 31,		
	2009	2008	2007
Sales and operating revenues	688,479	915,579	625,526
Interest revenue	351	932	2,180
Other non-allocated revenue	4,228	3,216	2,667
<b>Total revenue</b>	<b>693,058</b>	<b>919,727</b>	<b>630,373</b>
Cost of sales and operating expenses	(601,983)	(888,623)	(573,609)
Office and administration and other expenses	(44,894)	(46,691)	(41,274)
Derivative gain/(loss)	1,009	24,039	(7,272)
Exploration costs	(209)	(996)	(13,305)
Exploration impairment	-	(108)	(1,243)
Gain on sale of oil and gas properties assets	7,364	11,235	-
Loss on extinguishment of IPI liability	(31,710)	-	-
Gain on LNG shareholder agreement	-	-	6,553
Foreign Exchange gain/(loss)	(3,305)	3,878	5,078
<b>Earnings before interest, taxes, depreciation and amortization ("EBITDA" - non-GAAP measure) <sup>(1)</sup></b>	<b>19,330</b>	<b>22,461</b>	<b>5,301</b>
Depreciation and amortization	(14,322)	(14,143)	(13,024)
Interest expense	(9,993)	(20,032)	(20,005)
<b>Profit before income taxes and non-controlling interest</b>	<b>(4,985)</b>	<b>(11,714)</b>	<b>(27,728)</b>
Income tax benefit/(expense)	11,076	(82)	(1,207)
Non-controlling interest	(8)	(1)	22
<b>Net profit</b>	<b>6,083</b>	<b>(11,797)</b>	<b>(28,913)</b>
<b>Net profit per share (dollars) (basic)</b>	<b>0.15</b>	<b>(0.35)</b>	<b>(0.96)</b>
<b>Net profit per share (dollars) (diluted)</b>	<b>0.15</b>	<b>(0.35)</b>	<b>(0.96)</b>
<b>Total assets</b>	<b>631,754</b>	<b>591,843</b>	<b>537,815</b>
<b>Total liabilities</b>	<b>189,764</b>	<b>364,704</b>	<b>441,712</b>
<b>Total long-term liabilities</b>	<b>96,225</b>	<b>208,224</b>	<b>174,966</b>
<b>Gross margin <sup>(2)</sup></b>	<b>86,496</b>	<b>26,956</b>	<b>51,917</b>
<b>Cash flows provided by/(used in) operating activities <sup>(3)</sup></b>	<b>44,500</b>	<b>15,586</b>	<b>(31,620)</b>
<b>U.S. GAAP net profit (loss) <sup>(4)</sup></b>	<b>(622)</b>	<b>(3,943)</b>	<b>(19,205)</b>

Notes:

- (1) Earnings before interest, taxes, depreciation and amortization, or EBITDA, is a non-GAAP measure and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".
- (2) Gross Margin is a non-GAAP measure and is "sales and operating revenues" less "cost of sales and operating expenses" and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".
- (3) Refer to "Liquidity and Capital Resources – Summary of Cash Flows" for detailed cash flow analysis.
- (4) We are not presenting all the U.S. GAAP information in this MD&A. Readers should review note 30 – "Reconciliation to the generally accepted accounting principles in the United States" to the audited financial statements for the year ended December 31, 2009 for the reconciliation of the Canadian GAAP and U.S. GAAP information.

### **Analysis of Financial Condition Comparing Year Ended December 31, 2009 and 2008**

During the year ended December 31, 2009, we strengthened our financial position with the conversion of the remaining portion of the \$95.0 million 8% convertible subordinated debentures issued in May 2008 into our common shares, and the completion of the \$70.4 million registered direct common stock offering completed in

June 2009. These transactions combined with the exercise of all outstanding warrants and a net profit for the year reduced our debt-to-capital ratio to 11% for the year ended December 2009 from 36% as at December 31, 2008.

As at December 31, 2009, our total assets amounted to \$631.8 million as compared to \$591.8 million as at December 31, 2008, which is an increase of \$40.0 million or 6.8%. The increase is mainly due to the increase in the value of our oil and gas properties by \$44.5 million associated with the appraisal of the Elk and Antelope fields. This increase is net of cash calls from IPI investors and the \$24.2 million of gain on the sale of oil and gas properties in relation to 2.5% Elk and Antelope interest sold to Pacific LNG Operations Ltd, during the year. We have applied the sale proceeds against the cost base of the Elk and Antelope fields as recovery of cost.

As at December 31, 2009, our total liabilities amounted to \$189.8 million as compared to \$364.7 million as at December 31, 2008, which is a decrease in liability of \$174.9 million or 48.0%. The decrease was mainly the result of the conversion of the \$65.0 million remaining portion of the \$95.0 million 8% subordinated convertible debentures into common shares, \$44.2 million reduction in the working capital facility balances as at December 31, 2009 and a reduction in the IPI liability by \$33.8 million due to the waiver of conversion rights during the year by IPI investors coupled with the buyback of 4.8364% IPI interest.

Our current ratio (being current assets/current liabilities), which measures the ability to meet short term obligations, improved to 2.22 as at December 31, 2009 from 1.51 as at December 31, 2008. The quick ratio (or acid test ratio, being ([current assets less inventories]/current liabilities) which is a more conservative measure of our ability to meet short term obligations, improved to 1.47 as at December 31, 2009 from 0.98 as at December 31, 2008.

### ***Analysis of Consolidated Financial Results Comparing Year and Quarter Ended December 31, 2009 and 2008***

#### **Annual Comparative**

2009 was an improved year for us in relation to our operating results, especially given the global economic backdrop. 2009 is the first year of reporting an annualized net profit since we were formed in May 1997.

Net profit for the year ended December 31, 2009 was \$6.1 million compared with a net loss of \$11.8 million for the same period in 2008, showing an improvement of \$17.9 million. The operating segments of Corporate, Midstream Refining and Downstream collectively returned a net profit for the year of \$54.0 million while the development segments of Upstream and Midstream Liquefaction yielded a net loss of \$47.9 million for an aggregate net profit of \$6.1 million.

Sales and operating revenue for the year ended December 31, 2009 were \$693.1 million compared with \$919.7 million for the same period in 2008 mainly due to the lower crude price environment in the current year. The total volume of all products sold by us was 6.5 million barrels for fiscal year 2009 as compared to 6.6 million barrels in 2008.

EBITDA for the year ended December 31, 2009 was \$19.3 million, a reduction of \$3.1 million over the \$22.4 million for the same period in 2008. EBITDA for the year excluding the \$31.7 million "Loss on extinguishment of IPI liability" was \$51.0 million as compared to \$22.5 million in 2008. "Loss on extinguishment of IPI liability" of \$31.7 million relates to our buyback of 4.8364% IPI interest during 2009. We have adopted the extinguishment of liability model for accounting for this transaction with the difference between fair value and book value of the IPI liability for this interest being expensed. This transaction increases our net interest in the resource base as these IPI investors have no further rights to the Elk and Antelope fields or the remaining eight well exploration program provided for under the relevant 2005 Amended and Restated Indirect Participation Interest Agreement.

The Upstream segment had a net loss of \$39.5 million in 2009 (2008 – profit of \$2.2 million) mainly due to the \$31.7 million loss on extinguishment of the IPI liability as noted above, and the \$5.3 million higher intercompany interest charges due to higher loan balances from the parent entity (Corporate segment).

Midstream – Refining segment generated a net profit of \$41.8 million in 2009 (2008 - \$4.7 million) mainly on account of hedge accounted and non-hedge accounted derivative gains realized of \$18.2 million, better gross

margins due to higher yielding crude cargos and higher export premiums, and the recognition of \$14.3 million of deferred tax assets in relation to carried forward tax losses from prior years.

Midstream – Liquefaction segment had a loss of \$8.4 million (2008 - \$7.9 million) during the 2009 year in relation to our share of the LNG project expenses. As the Project Agreement was signed by the Government of Papua New Guinea in December 2009, all direct project related costs from January 1, 2010 will be capitalized to the project rather than expensed.

Downstream segment generated a net profit of \$8.5 million in 2009 (2008 – loss of \$1.2 million) mainly on the basis of the positive effect of product price movements as applied to inventory held during the year.

The Corporate segment generated a net profit of \$4.3 million (2008 – loss of \$10.6 million) primarily due to intercompany interest recharges on loans provided to other segments and a \$6.8 million reduction in the interest expense on borrowings compared to the prior year. The reduction in interest expense is due to the conversion of all outstanding debentures into common shares, and the repayment of our bridging facility in May 2008 with no corresponding interest expense in 2009.

### Quarterly Comparative

The net profit for the quarter ended December 31, 2009 was \$19.3 million compared with a loss of \$34.2 million for the same quarter of 2008, an improvement of \$53.5 million. EBITDA for the quarter ended December 31, 2009 was \$9.1 million, compared with a negative \$28.8 million in the same quarter of 2008, an improvement of \$37.9 million.

The operating segments of Corporate, Midstream - Refining and Downstream collectively derived a net profit for the fourth quarter of 2009 of \$24.5 million, and the development segments of Upstream and Midstream Liquefaction had a net loss of \$5.2 million for an aggregate net profit of \$19.3 million.

Sales and operating revenue decreased \$9.3 million from \$218.6 million in the quarter ended December 31, 2008 to \$209.3 million in the quarter ended December 31, 2009. The total volume of all products sold by us was 1.8 million barrels for quarter ended December 31, 2009 as compared to 1.7 million barrels for the same quarter of 2008.

### Variance Analysis

A detailed discussion of each of our business segment's results can be found under the section "Year and Quarter in Review". The following analysis outlines the key variances, the net of which are the primary explanations for the changes in the results between the years and quarters ended December 31, 2009 and 2008.

	<b>Yearly Variance</b>	<b>Quarterly Variance</b>	
	<b>(\$ millions)</b>	<b>(\$ millions)</b>	
	<b>\$17.9</b>	<b>\$53.5</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$59.5	\$56.5	Increase in gross margins mainly due to hedging gains, improving product price environment, lower inventory write downs, higher yielding crude cargoes and higher premiums on export products.
➤	(\$23.0)	(\$23.2)	Lower derivative gains from non-hedge accounted contracts.
➤	(\$3.9)	\$6.3	A gain of \$7.4 million was made in 2009 was on account of waiver of common stock conversion rights for a 6.210% IPI interest. 2008 gains included gain on sale of PRL 4/5 for \$6.5 million and waiver of 5.225% IPI interest resulting in a gain on conveyance of \$4.7 million.
➤	(\$31.7)	(\$3.1)	Loss on extinguishment of IPI liability relating to buyback of 4.3346% IPI interest in September 2009 and a further 0.5% in December 2009, with the difference between fair value and book value of the IPI liability expensed under the extinguishment of liability accounting model.

➤	(\$7.2)	\$2.1	Impact of foreign exchange movements as the PGK has been very volatile against the USD during the 2009 periods.
➤	\$10.0	\$4.4	Lower interest expense primarily due to part conversion and repayment of the Merrill Lynch bridging facility which occurred in May 2008 and then the mandatory conversion in June 2009 of the remaining portion of the \$95.0 million 8% convertible debentures in May 2008.
➤	\$11.2	\$11.1	Reduced income tax expense due to recognition of future income tax benefit relating to carried forward tax losses and other temporary differences.
➤	\$3.0	(\$0.6)	Other miscellaneous variances with the decrease in yearly expenses mainly relating to lower legal and project related consulting expenses.

### ***Analysis of Consolidated Cash Flows Comparing Year Ended December 31, 2009 and 2008***

As at December 31, 2009, we had cash, cash equivalents and cash restricted of \$75.8 million (December 2008 – \$75.3 million), of which \$22.9 million (December 2008 - \$26.3 million) was restricted pursuant to the BNP Paribas working capital facility utilization requirements, and \$6.4 million (December 2008 – nil) was restricted as cash deposit on the Overseas Petroleum Investment Corporation (“OPIC”) secured loan.

The cash held as a deposit for the OPIC secured loan relates to our half yearly installment of \$4.5 million and the related interest that will be payable with the next installment on June 30, 2010. The waiver in respect of this deposit requirement expired in June 2009 with the completion of the capital raising of \$70.4 million.

Our cash inflows from operations for the 2009 year ended December 31, 2009 were \$44.5 million compared with \$15.6 million for the year ended December 31, 2008. The improved cash flows from operations for the year were mainly due to improved margins generated in the Midstream Refining and Downstream segments, and cash received on the close out of long term hedges.

Cash outflows for investing activities for the year ended December 31, 2009 were \$85.6 million compared with \$47.4 million for 2008. These outflows mainly relate to the net cash expenditure on exploration activities net of IPI cash calls, and expenditure on plant and equipment.

Cash inflows from financing activities for the year ended December 31, 2009 were \$38.5 million compared with \$36.9 million for the year ended December 31, 2008. The financing activities section in the cash flow statement includes the capital and debt raisings by us, exercise of warrants, as well as the movement in the working capital facility balance with BNP Paribas. The cash inflows/outflows due to the working capital facility drawdown/repayments are due to the timing of cash flows and use of working capital from our Midstream Refining and Downstream segments.

## Summary of Consolidated Quarterly Financial Results for Past Eight Quarters

The following is a table containing the consolidated results for the eight quarters ended December 31, 2009 by business segment, and on a consolidated basis.

Quarters ended (\$ thousands except per share data)	2009				2008			
	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31
Upstream	1,027	1,011	660	611	487	698	895	618
Midstream – Refining	173,438	141,295	114,347	145,523	194,617	216,750	197,864	176,973
Midstream – Liquefaction	0	1	2	4	23	35	19	13
Downstream	118,270	107,712	85,472	78,572	128,540	172,528	140,467	116,048
Corporate	10,539	10,087	8,640	7,753	9,591	8,415	8,334	8,531
Consolidation entries	(93,971)	(86,509)	(60,625)	(70,801)	(114,691)	(134,695)	(102,565)	(109,769)
<b>Sales and operating revenues</b>	<b>209,303</b>	<b>173,597</b>	<b>148,496</b>	<b>161,662</b>	<b>218,567</b>	<b>263,731</b>	<b>245,014</b>	<b>192,414</b>
Upstream	574	(29,097)	(669)	(469)	(2,483)	231	10,164	(1,135)
Midstream – Refining	8,492	8,199	14,134	14,747	(13,976)	17,516	16,329	5,724
Midstream – Liquefaction	(1,200)	(2,119)	(1,379)	(2,361)	(2,501)	(1,570)	(1,784)	(1,636)
Downstream	4,391	6,542	4,150	3,241	(7,244)	610	7,893	4,529
Corporate	1,765	1,980	1,897	3,051	226	764	(2,155)	1,796
Consolidation entries	(4,884)	(4,092)	(278)	(7,285)	(2,865)	(737)	(3,093)	(2,143)
<b>EBITDA <sup>(1)</sup></b>	<b>9,138</b>	<b>(18,587)</b>	<b>17,855</b>	<b>10,924</b>	<b>(28,843)</b>	<b>16,814</b>	<b>27,354</b>	<b>7,135</b>
Upstream	(3,626)	(31,392)	(2,382)	(2,133)	(4,003)	(1,039)	9,188	(1,993)
Midstream – Refining	18,070	3,762	9,624	10,350	(19,490)	12,660	11,344	202
Midstream – Liquefaction	(1,591)	(2,481)	(1,765)	(2,552)	(2,597)	(1,677)	(1,909)	(1,728)
Downstream	2,371	3,440	1,742	964	(5,901)	(886)	3,383	2,198
Corporate	3,036	1,602	(677)	349	(2,275)	(1,759)	(5,164)	(1,390)
Consolidation entries	1,047	(237)	2,894	(4,332)	37	1,928	(1,241)	315
<b>Net profit/(loss) per segment</b>	<b>19,307</b>	<b>(25,306)</b>	<b>9,436</b>	<b>2,646</b>	<b>(34,229)</b>	<b>9,227</b>	<b>15,601</b>	<b>(2,396)</b>
<b>Net profit/(loss) per share (dollars)</b>								
Per Share – Basic	0.45	(0.60)	0.25	0.07	(0.96)	0.26	0.48	(0.08)
Per Share – Diluted	0.43	(0.60)	0.24	0.07	(0.96)	0.22	0.40	(0.08)

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

## YEAR AND QUARTER IN REVIEW

The following section provides a review of the year and quarter ended December 31, 2009 for each of our business segments.

### UPSTREAM – YEAR AND QUARTER IN REVIEW

Upstream – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
Other non-allocated revenue	3,309	2,697
<b>Total revenue</b>	<b>3,309</b>	<b>2,697</b>
Office and administration and other expenses	(7,111)	(5,919)
Exploration costs	(209)	(996)
Exploration impairment	-	(108)
Gain on sale of oil and gas properties	7,364	11,235
Loss on extinguishment of IPI liability	(31,710)	-
Foreign Exchange gain/(loss)	(1,304)	(132)
<b>EBITDA (non-GAAP measure) <sup>(1)</sup></b>	<b>(29,661)</b>	<b>6,777</b>
Depreciation and amortization	(538)	(597)
Interest expense	(9,335)	(4,027)
<b>Loss before income taxes and non-controlling interest</b>	<b>(39,534)</b>	<b>2,153</b>
Income tax expense	-	-
<b>Net (loss)/profit</b>	<b>(39,534)</b>	<b>2,153</b>

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### Analysis of Upstream Financial Results Comparing Quarter and Year Ended December 31, 2009 and 2008

The following analysis outlines the key movements, the net of which primarily explains the difference in the results between the years and quarters ended December 31, 2009 and 2008.

Yearly Variance (\$ millions)	Quarterly Variance (\$ millions)	
<b>(\$41.7)</b>	<b>\$0.4</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤ (\$3.9)	\$6.3	A gain of \$7.4 million was made in 2009 due to waiver of common stock conversion rights for 6.210% IPI interest. 2008 gains included gain on sale of PRL 4/5 for \$6.5 million and waiver of 5.225% IPI interest resulting in a gain on conveyance of \$4.7 million.
➤ (\$31.7)	(\$3.1)	Loss on extinguishment of IPI liability relating to buyback of 4.3346% IPI interest in September 2009 and a further 0.5% in December 2009, with the difference between fair value and book value of the IPI liability expensed under the extinguishment of liability accounting model.
➤ (\$5.3)	(\$2.7)	Higher interest expense due to an increase in inter-company loan balances.

## MIDSTREAM REFINING – YEAR AND QUARTER IN REVIEW

Midstream Refining – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
External sales	299,673	358,896
Inter-segment revenue	274,736	427,218
Interest and other revenue	194	90
<b>Total segment revenue</b>	<b>574,603</b>	<b>786,204</b>
Cost of sales and operating expenses	(516,349)	(779,832)
Office and administration and other expenses	(9,901)	(10,081)
Derivative gain/(loss)	1,009	24,039
Foreign Exchange gain/(loss)	(3,790)	5,264
<b>EBITDA (non-GAAP measure) <sup>(1)</sup></b>	<b>45,572</b>	<b>25,594</b>
Depreciation and amortization	(10,932)	(10,969)
Interest expense	(7,150)	(9,908)
<b>Profit before income taxes and non-controlling interest</b>	<b>27,490</b>	<b>4,717</b>
Income tax expense	14,316	-
Non-controlling interest	-	-
<b>Net profit</b>	<b>41,806</b>	<b>4,717</b>
<b>Gross Margin <sup>(2)</sup></b>	<b>58,060</b>	<b>6,282</b>

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(2) Gross Margin is a non-GAAP measure and is external sales and inter-segment revenue less cost of sales and operating expenses and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### Midstream Refining Operating Review

Key Refining Metrics	Quarter ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Throughput (barrels per day) <sup>(1)</sup>	20,966	21,206	21,155	22,034
Capacity utilization (based on 36,500 barrels per day operating capacity)	44%	57%	47%	44%
Cost of production per barrel <sup>(2)</sup>	\$2.92	\$2.45	\$3.18	\$2.97
Working capital financing cost per barrel of production <sup>(2)</sup>	\$0.49	\$0.57	\$0.40	\$1.01
Distillates as percentage of production	61.00%	53.60%	58.63%	56.00%

(1) Throughput per day has been calculated excluding shut down days. During 2009 and 2008, the refinery was shut down for 80 days and 101 days, respectively.

(2) Our cost of production per barrel and working capital financing cost per barrel have been calculated based on a notional throughput. Our actual throughput has been adjusted to include the throughput that would have been necessary to produce the equivalent amount of diesel that we imported during the year.

**Analysis of Midstream - Refining Financial Results Comparing the Year and Quarter Ended December 31, 2009 and 2008**

The following analysis outlines the key movements, the net of which primarily explains the improvements in the results between the year and quarter ended December 31, 2009 and 2008.

	<b>Yearly Variance</b>	<b>Quarterly Variance</b>	
	<b>(\$ millions)</b>	<b>(\$ millions)</b>	
	<b>\$37.1</b>	<b>\$37.6</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$51.8	\$42.8	Change in Gross Margin was due to the following contributing factors: <ul style="list-style-type: none"> <li>+ Less volatility in crude prices in 2009. The rapid fall in crude prices in the fourth quarter of 2008 reduced the gross margins of our refinery operations by approximately \$45.9 million. This includes a year-end inventory devaluation of \$4.2 million.</li> <li>+ Availability of preferred crude feedstock resulting in stronger refining yield structure and higher distillate production percentage in 2009.</li> <li>+ Hedge gains realized on close out of long term hedges in early 2009.</li> <li>+ Improved Naphtha premium in 2009 contract.</li> <li>- The above improvements have been partly offset by weaker distillate margins in 2009 which has adversely affected the refining industry in general due to lower worldwide demand.</li> </ul>
➤	(\$23.0)	(\$23.2)	Decrease in derivative gains from non-hedge accounted contracts.
➤	\$2.8	\$0.8	Reduction in interest expense as a result of a decrease in inter-company loans (due to conversion of debt to equity on certain intercompany balances) and principal repayments made on the OPIC secured loan.
➤	(\$9.1)	\$3.0	(Reduction)/increase in foreign exchange gains due to the currency fluctuations between PGK and the U.S. Dollar.
➤	\$14.3	\$14.3	Recognition of future income tax benefit relating to carried forward tax losses and other temporary differences as management now considers it is more likely than not that the deferred tax assets will be realized.

## MIDSTREAM LIQUEFACTION – YEAR AND QUARTER IN REVIEW

Midstream Liquefaction – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
Interest and other revenue	8	91
<b>Total segment revenue</b>	<b>8</b>	<b>91</b>
Office and administration and other expenses	(7,108)	(7,022)
Foreign Exchange gain/(loss)	41	(560)
<b>EBITDA (non-GAAP measure) <sup>(1)</sup></b>	<b>(7,059)</b>	<b>(7,491)</b>
Depreciation and amortization	(57)	(69)
Interest expense	(1,218)	(241)
<b>Loss before income taxes and non-controlling interest</b>	<b>(8,334)</b>	<b>(7,801)</b>
Income tax expense	(55)	(110)
<b>Net loss</b>	<b>(8,389)</b>	<b>(7,911)</b>

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### **Analysis of Midstream Liquefaction Financial Results Comparing the Years and Quarters Ended December 31, 2009 and 2008**

This segment results include the proportionate consolidation of PNG LNG Inc., the Joint Venture Entity, and InterOil LNG Holdings Inc., holding company for our interest in the Joint Venture.

All costs incurred, subsequent to the execution of the shareholders' agreement on July 31, 2007, during the pre-acquisition and construction stage have been expensed as incurred, unless they were directly identified with the property, plant and equipment of the LNG Project. As at December 31, 2009, we had capitalized \$2.3 million of such direct costs to the project and expensed costs relating to employees, office premises and consultants.

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the year and quarter ended December 31, 2009 and 2008.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$0.5)</b>	<b>\$1.0</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$1.5	\$0.9	Reduction in office, administration and other expenses due to the reduced consulting expenses incurred in furthering the liquefaction facility. During second quarter of 2009, the Australian project office was closed and work transferred to our newly established project office in Singapore.
➤	(\$1.5)	-	Relates to the increased loss on proportionate consolidation of PNG LNG Inc. subsequent to the acquisition of Merrill Lynch's interest. These losses be recouped as the remaining joint venture partner equalizes its interests through payment of cash calls.
➤	(\$1.0)	(\$0.3)	Increase in interest expense charged from the Corporate Segment due to higher inter-company loan balances following the Merrill Lynch interest acquisition.

## DOWNSTREAM YEAR AND QUARTER IN REVIEW

Downstream – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
External sales	388,806	556,683
Inter-segment revenue	185	185
Interest and other revenue	1,035	715
<b>Total segment revenue</b>	<b>390,026</b>	<b>557,583</b>
Cost of sales and operating expenses	(359,623)	(536,920)
Office and administration and other expenses	(12,911)	(14,669)
Foreign Exchange gain/(loss)	832	(207)
<b>EBITDA (non-GAAP measure) <sup>(1)</sup></b>	<b>18,324</b>	<b>5,787</b>
Depreciation and amortization	(2,650)	(2,571)
Interest expense	(4,130)	(4,838)
<b>Profit before income taxes and non-controlling interest</b>	<b>11,544</b>	<b>(1,622)</b>
Income tax expense	(3,027)	414
<b>Net profit</b>	<b>8,517</b>	<b>(1,208)</b>
<b>Gross Margin <sup>(2)</sup></b>	<b>29,368</b>	<b>19,948</b>

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(2) Gross Margin is a non-GAAP measure and is "external sales" and "inter-segment revenue" less "cost of sales and operating expenses" and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### Downstream Operating Review

Key Downstream Metrics	Quarter Ended December 31,		Year Ended December 31,	
	2009	2008	2009	2008
Sales volumes (millions of liters)	159.1	151.4	588.8	548.0
Cost of distribution per liter (\$ per liter) <sup>(1)</sup>	\$0.06	\$0.07	\$0.06	\$0.06

(1) Cost of distribution per liter includes land based freight costs and operational costs. It excludes depreciation and interest.

### Analysis of Downstream Financial Results Comparing the Years and Quarters Ended December 31, 2009 and 2008

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the years and quarters ended December 31, 2009 and 2008.

Yearly Variance (\$ millions)	Quarterly Variance (\$ millions)	
\$9.7	\$8.3	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤ \$9.4	\$12.6	Increase in gross margin mainly due to the positive effect of product price movements as applied to the inventory sold during the period. The fourth quarter of 2008 saw a significant fall in product prices resulting in the negative gross margin for the year and quarter ended December 31, 2008. The less volatile and gradually increasing price environment has improved the Downstream gross margins compared to prior periods.

- \$1.8 (\$1.4) Reduction in office and administration and other expenses for the year mainly due to lower provisions for doubtful debts.
- \$0.8 \$1.3 Reduction in interest expense compared with prior periods due to lower working capital requirements in lower pricing environment.
- (\$3.4) (\$4.7) Increase in income tax expense in line with movements in Downstream operating profits.
- \$1.0 (\$0.1) Foreign exchange movements during the periods due to the currency fluctuations between PGK and the USD.

## CORPORATE – YEAR AND QUARTER IN REVIEW

Corporate – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
Inter-segment revenue	21,194	24,568
Interest revenue	15,825	10,303
<b>Total revenue</b>	<b>37,019</b>	<b>34,871</b>
Office and administration and other expenses	(29,241)	(33,753)
Foreign Exchange gain/(loss)	915	(486)
<b>EBITDA (non-GAAP measure) <sup>(1)</sup></b>	<b>8,693</b>	<b>632</b>
Depreciation and amortization	(275)	(66)
Interest expense	(3,952)	(10,766)
<b>Profit/(loss) before income taxes and non-controlling interest</b>	<b>4,466</b>	<b>(10,200)</b>
Income tax expense	(158)	(386)
<b>Net profit/(loss)</b>	<b>4,308</b>	<b>(10,586)</b>

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### Analysis of Corporate Financial Results Comparing the Years and Quarters Ended December 31, 2009 and 2008

The following table outlines the key movements, the net of which primarily explains the variance in the results for between the years and quarters ended December 31, 2009 and 2008.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>\$14.9</b>	<b>\$5.3</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$12.3	\$5.3	Reduced interest expenses (net of recharged intercompany interest revenue from other segments) due to part conversion, and part repayment of Merrill Lynch bridging facility in May 2008 plus mandatory conversion in June 2009 on the remaining portion of the \$95.0 million debentures issued in May 2008.
➤	\$1.1	(\$0.6)	Reduction in net office and administration and other expenses after recharges to other streams (included in inter-segment revenue) for the year mainly due to lower legal consulting costs.
➤	\$1.4	(\$0.8)	Increase/(Decrease) in foreign exchange gains due to the currency fluctuations between Australian Dollar ("AUD") and the U.S. Dollar.

- \$0.2      \$1.5      Reduction in income tax expense during the period primarily due to a the recognition of future income tax benefits.

## CONSOLIDATION ADJUSTMENTS – YEAR AND QUARTER IN REVIEW

Consolidation adjustments – Operating results (\$ thousands, unless otherwise indicated)	Year ended December 31,	
	2009	2008
Inter-segment revenue <sup>(1)</sup>	(296,115)	(451,970)
Interest revenue <sup>(5)</sup>	(15,792)	(9,748)
Other non-allocated revenue	-	-
<b>Total revenue</b>	<b>(311,907)</b>	<b>(461,718)</b>
Cost of sales and operating expenses <sup>(1)</sup>	273,989	428,129
Office and administration and other expenses <sup>(2)</sup>	21,379	24,753
Foreign Exchange gain/(loss)	-	-
<b>EBITDA (non-GAAP measure) <sup>(3)</sup></b>	<b>(16,539)</b>	<b>(8,836)</b>
Depreciation and amortization <sup>(4)</sup>	130	130
Interest expense <sup>(5)</sup>	15,792	9,747
<b>Profit/(loss) before income taxes and non-controlling interest</b>	<b>(617)</b>	<b>1,041</b>
Income tax expense	-	-
Non-controlling interest	(8)	(1)
<b>Net profit/(loss)</b>	<b>(625)</b>	<b>1,040</b>
<b>Gross Margin <sup>(6)</sup></b>	<b>(22,126)</b>	<b>(23,841)</b>

(1) Represents the elimination upon consolidation of our refinery sales to other segments and other minor inter-company product sales.

(2) Includes the elimination of inter-segment administration service fees.

(3) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(4) Represents the amortization of a portion of costs capitalized to assets on consolidation.

(5) Includes the elimination of interest accrued between segments.

(6) Gross Margin is a non-GAAP measure and is "inter-segment revenue elimination" less "cost of sales and operating expenses" and represents elimination upon consolidation of our refinery sales to other segments. This measure is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

### Analysis of Consolidation Adjustments Comparing the Years and Quarters Ended December 31, 2009 and 2008

The following table outlines the key movements, the net of which primarily explains the variance in the results for between the years and quarters ended December 31, 2009 and 2008.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$1.7)</b>	<b>\$1.0</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$1.7	\$3.0	Increase in net income due to recognition of intra-group profit eliminated on consolidation between Midstream – Refining and Downstream segments in the prior periods relating to the Midstream – Refining segment's profit component of inventory on hand in the Downstream segment at period ends.
➤	(\$3.4)	(\$2.0)	Elimination of inter-segment administration service fees.

## LIQUIDITY AND CAPITAL RESOURCES

### Summary of Debt Facilities

Summarized below are the debt facilities available to us and the balances outstanding as at December 31, 2009.

Organization	Facility	Balance outstanding December 31, 2009	Maturity date
OPIC secured loan	\$53,500,000	\$53,500,000	December 2015
BNP Paribas working capital facility	\$190,000,000	\$16,794,153 <sup>(1)</sup>	December 2010
Westpac working capital facility	\$29,600,000	\$7,832,266	October 2011
BSP working capital facility	\$18,500,000	\$0	August 2010

(1) Excludes letters of credit totaling \$56.7 million.

#### *OPIC Secured Loan (Midstream)*

On September 12, 2001, we entered into a loan agreement with OPIC with respect to an \$85.0 million project financing facility for the development of our refinery in PNG. The loan is secured by the assets of the refinery. The interest rate on the loan is equal to the agreed U.S. Government treasury cost applicable to each promissory note outstanding plus 3%, and is payable quarterly in arrears. Principal repayments of \$4.5 million each are due on June 30 and December 31 of each year until December 31, 2015. During the year ended December 31 2009, two installments of \$4.5 million each and the accrued interest on the loan were paid.

#### *BNP Paribas Working Capital Facility (Midstream)*

This working capital facility is used to finance purchases of crude feedstock for our refinery. In accordance with the agreement with BNP Paribas, the total facility is split into two components, Facility 1 and Facility 2. Facility 1 is for \$130.0 million and can be used for the issuance of documentary letters of credit and or standby letters of credit, short term advances, advances on merchandise, freight loans, receivables financing and a sublimit of Euro 18.0 million or USD equivalent for hedging transactions via BNP Paribas Commodity Indexed Transaction Group or other acceptable counter parties. Facility 2 amounts to \$60.0 million and can be used for partly cash-secured short term advances and for discounting of any monetary receivables acceptable to BNP Paribas. The facility is secured by sales contracts, purchase contracts, certain cash accounts associated with the refinery, all crude and refined products of the refinery and trade receivables.

The facility is renewable annually. During the quarter ended December 31, 2009, the facility was renewed for a period of fifteen months to December 31, 2010.

As of December 31, 2009, \$116.5 million remained available for use under the facility. The weighted average interest rate under the working capital facility was 2.13% for the year ended December 31, 2009 compared to 5.11% for 2008. The interest rate applicable to this facility has declined in line with the reduction in LIBOR rates during the year.

#### *Bank South Pacific and Westpac Working Capital Facility (Downstream)*

On October 24, 2008, we secured a PGK 150.0 million (approximately \$55.5 million) combined revolving working capital facility for our Downstream wholesale and retail petroleum products distribution business in Papua New Guinea from Bank of South Pacific Limited and Westpac Bank PNG Limited. The facility limit as at December 31, 2009 was PGK 130.0 million (approximately \$48.1 million).

The Westpac facility limit is PGK 80.0 million (approximately \$29.6 million) and the BSP facility limit was initially PGK 70.0 million (approximately \$25.9 million). The Westpac facility is for an initial term of three years and is due for renewal in October 2011. The BSP facility is renewable annually and was renewed in October 2009 at a lower limit of Papua New Guinea Kina 50.0 million (approximately \$18.5 million). As at December 31, 2009, only \$7.8 million of this combined facility had been utilized, and the remainder was available for use. The weighted average interest rate under the Westpac facility was 9.16% for the year to December 31, 2009. The weighted average interest rate under the BSP facility was 9.27% for the year to December 31, 2009.

While cash flows from operations are expected to be sufficient to cover our operating commitments, should there be a major deterioration in refining or downstream margins, our operations may not generate sufficient cash flows to cover all of the interest and principal payments under our debt facilities noted above. As a result, we may be required to raise additional capital and/or refinance these facilities in the future. We can provide no assurances that we will be able to obtain such additional capital or that our lenders will agree to refinance these debt facilities, or, if available, that the terms of any such capital raising or refinancing will be acceptable to us.

## Other Sources of Capital

### Upstream

Currently our share of expenditures on exploration wells, appraisal wells and extended well programs are funded from equity raising activities, operational cash flows and asset sales.

On October 30, 2008, Petromin PNG Holdings Limited ("Petromin"), a government entity mandated to invest in resource projects on behalf of the Independent State of Papua New Guinea ("the State"), entered into an agreement to take a 20.5% direct interest in the Elk and Antelope fields. If certain conditions in the agreement are met, Petromin has agreed to fund 20.5% of the costs of developing the Elk and Antelope fields. The State's right to invest arises under legislation and is exercisable upon issuance of the Petroleum Development License ("PDL"), which has not yet occurred. The agreement contains certain provisions applicable in the event that the PDL is not issued within a certain timeframe. During 2009, the State confirmed Petromin's nomination to exercise its interest in the Elk and Antelope fields. On grant of a PDL, Petromin has agreed to pay us 20.5% of all other sunk costs incurred by InterOil prior to entering into the agreement. Until the PDL is granted, any payment made by Petromin is to be separately held in a liability account in accordance with the provisions of the agreement. Once the PDL is granted, the conveyance of this interest to the State is able to be formalized, and we are obliged to distribute the proceeds received from Petromin between the existing interest holders (InterOil, IPI holders and PNGDV) on a pro-rata basis based on the interest surrendered by each to the State. The State may also elect to participate in a further 2.0% working interest on behalf of the landowners of the licensed areas. As at December 31, 2009, \$10.4 million had been received from Petromin.

Cash calls are made on IPI investors, Pacific LNG Operations Ltd (for its 2.5% direct interest acquired during the year) and Petromin for their share of amounts spent on appraisal wells and extended well programs pursuant to the relevant agreements in place with them.

## Summary of Cash Flows

(\$ thousands)	Year ended December 31		
	2009	2008	2007
<b>Net cash inflows/(outflows) from:</b>			
Operations	44,500	15,586	(31,620)
Investing	(85,567)	(47,391)	(34,370)
Financing	38,546	36,913	78,170
<b>Net cash movement</b>	<b>(2,521)</b>	<b>5,108</b>	<b>12,180</b>
Opening cash	48,970	43,862	31,682
<b>Closing cash</b>	<b>46,449</b>	<b>48,970</b>	<b>43,862</b>

**Analysis of Cash Flows Provided By/(Used In) Operating Activities Comparing the Years Ended December 31, 2009 and 2008**

The following table outlines the key variances in the cash flows from operating activities between year ended December 31, 2009 and 2008:

<b>Yearly Variance (\$ millions)</b>	
<b>\$28.9</b>	<b>Variance for the comparative periods primarily due to:</b>
➤ \$65.0	Increase in cash provided by operations prior to changes in operating working capital due to improved margins from operations.
➤ (\$36.1)	(Increase)/Decrease in cash used by operations due to the timing of receipts, payments and inventory purchases.

**Analysis of Cash Flows Provided By/(Used In) Investing Activities Comparing the Years Ended December 31, 2009 and 2008**

The following table outlines the key variances in the cash flows from investing activities between year ended December 31, 2009 and 2008:

<b>Yearly Variance (\$ millions)</b>	
<b>(\$38.2)</b>	<b>Variance for the comparative periods primarily due to:</b>
➤ (\$27.9)	Higher cash outflows for the year to December 31, 2009 on exploration expenditures compared to the prior year period. The outflows related to the Antelope -1 and 2 drilling and extended well drilling program. The extended well program is partly funded by cash calls to the IPI investors.
➤ (\$2.9)	Lower cash calls and related inflows from IPI investors as compared to prior year.
➤ (\$6.6)	Higher expenditure on acquisition of plant and equipment as compared to prior periods mainly related to the purchase of land and improvements associated with our service stations in Papua New Guinea, purchase of refinery laboratory equipments and implementation of a new enterprise resource planning ("ERP") system.
➤ (\$6.5)	Proceeds from sale of our interest in PRL's 4 and 5 during the year ended December 31, 2008.
➤ \$0.9	Lower cash outflows in the year due to movement in our secured cash restricted balances in line with the usage of the BNP working capital facility at period ends.
➤ \$5.2	Reduction in cash used in our Upstream development segment for working capital requirements. This working capital relates to movements in accounts payable and accruals in our Upstream operations.

**Analysis of Cash Flows Provided By/(Used In) Financing Activities Comparing the Years Ended December 31, 2009 and 2008**

The following table outlines the key variances in the cash flows from financing activities between years ended December 31, 2009 and 2008:

**Yearly  
Variance  
(\$ millions)**

<b>\$1.6</b>	<b>Variance for the comparative periods primarily due to:</b>
➤ (\$46.5)	Higher repayments made in respect of BNP Paribas working capital facility as compared to the prior year.
➤ \$70.0	Repayment of the Merrill Lynch bridging facility during the year ended December 31, 2008.
➤ (\$9.4)	Lower cash inflows relating to the LNG Project joint venture cash calls. There were no cash calls in the year ended December 31, 2009 compared with \$9.4 million during 2008.
➤ (\$1.9)	Lower cash inflows relating to the option and final agreement with Pacific LNG Operations Ltd under which it agreed to pay cash consideration of \$25.0 million to acquire a 2.5% interest in the Elk and Antelope fields. Cash inflows were \$3.6 million in the year ended December 31, 2009 compared with \$5.5 million in 2008.
➤ \$2.4	Net payments received from Petromin during 2009 for contributions towards cash calls made with respect to Elk and Antelope fields development activities.
➤ \$81.8	Net proceeds from the issuance of common shares during 2009 including \$70.4 million from a private placement offering in June 2009 and \$6.6 proceeds received on exercise of warrants in August 2009.
➤ (\$94.8)	Net proceeds from the issuance of 8% debentures during 2008.

## Capital Expenditures

### Upstream Capital Expenditures

Gross capital expenditures for exploration in Papua New Guinea for the year ended December 31, 2009 were \$91.8 million compared with \$63.9 million during the same period of 2008.

The following table outlines the key expenditures in the year ended December 31, 2009:

<b>Yearly (\$ millions)</b>	<b>Expenditures in the year ended December 31, 2009 due to:</b>
<b>\$91.8</b>	
➤ \$5.5	Preparatory/drilling costs on the Antelope-1 appraisal well.
➤ \$11.3	Testing of the Antelope-1 appraisal well.
➤ \$19.9	Preparatory/drilling costs on the Antelope-1 appraisal well side track.
➤ \$43.2	Preparatory/drilling costs on the Antelope-2 appraisal well.
➤ \$2.1	Costs incurred in developing the PDL for the Elk and Antelope fields.
➤ \$3.3	Site preparation costs for the Antelope-3 appraisal well
➤ \$2.8	Costs for early works on Antelope condensate stripping project
➤ \$3.7	Other expenditure, including fixed assets and drilling consumable purchases.

IPI investors and Pacific LNG Operations (2.5% direct interest in Elk and Antelope fields) are required to fund 25.8386% as at December 31, 2009 of the Elk and Antelope extended well program costs to maintain their

interest in that well program. This is the net interest to be funded by third parties after the completion of IPI buyback of 4.8364% by us and the sale of 2.5% interest to Pacific LNG Operations Limited in September 2009 pursuant to the option agreement of 2007. The amounts capitalized in our books, or expensed as incurred, in relation to the extended well program are the net amounts after adjusting these interest in the program.

Petromin PNG Holdings Limited ("Petromin") will fund 20.5% of ongoing costs for developing the fields. Petromin contributed \$10.4 million in the year ended December 31, 2009. All funds received are being treated as a deposit until a PDL is granted.

#### *Midstream Capital Expenditures*

Capital expenditures totaled \$2.2 million in our Midstream refinery segment for the year ended December 31, 2009 mainly in relation to tank upgrades and the purchase of laboratory equipment. All costs incurred during the year in relation to the Midstream Liquefaction segment have been expensed. Since the Project Agreement with the State of Papua New Guinea in relation to the development of the proposed liquefaction facilities was executed on 23 December 2009, all associated development costs from 1 January 2010 will now be capitalized.

#### *Downstream Capital Expenditures*

Capital expenditures for the Downstream segment totaled \$6.9 million for the year ended December 31, 2009. These expenditures mainly related to the purchase of land and improvements associated with service stations acquired in Papua New Guinea.

#### *Corporate Capital Expenditures*

Capital expenditures for the Corporate segment totaled \$2.5 million for the year ended December 31, 2009. These expenditures mainly related to project costs in relation to the ERP implementation across all streams. The implementation is expected to be completed by the third quarter of 2010.

### **Capital Requirements**

The oil and gas exploration and development, refining and liquefaction industries are capital intensive and our business plans necessarily involve raising additional capital. The availability and cost of such capital is highly dependent on market conditions at the time we raise such capital. No assurance can be given that we will be successful in obtaining new sources of capital on terms that are acceptable to us, particularly given continuing market conditions.

#### *Upstream*

We are required under our \$125.0 million Amended and Restated Indirect Participation Agreement ("IPI Agreement") of 2005 to drill eight exploration wells. We have drilled four wells to date. As at December 31, 2009, we are committed to spend a further \$83.0 million as a condition of renewal of our petroleum prospecting and retention licenses up to 2014. Of this \$83.0 million commitment, as at December 31, 2009, management estimates that \$46.3 million would satisfy the commitments in relation to the Amended and Restated IPI Agreement of February 2005..

We will need to raise additional funds in order for us to complete the programs and meet our exploration commitments. Therefore, we must extend or secure sufficient funding through renewed borrowings, equity raising and or asset sales to enable the availability of sufficient cash to meet these obligations over time and complete these long term plans. No assurances can be given that we will be successful in obtaining new sources of capital on terms acceptable to us, particularly given the current market conditions.

In the event that we establish sufficient gas reserves, we will also be required to obtain substantial amounts of financing for the development of Elk and Antelope fields, condensate stripping plant and delivery of gas to the LNG Project and it would take a number of years to complete these projects. In the event that the commercial viability of these projects are established, we plan to use a combination of debt, equity and the partial sale of

capitalized properties to raise adequate capital. The availability and cost of various sources of financing is highly dependent on market conditions at the time and we can provide no assurances that we will be able to obtain such financing or conduct such sales on terms that are acceptable. If the disruption in the financial and credit markets continue for an extended period of time, this financing may be more expensive and difficult to obtain.

#### *Midstream - Refining*

We believe that we will have sufficient funds from our operating cash flows to pay our estimated capital expenditures associated with our Midstream – Refining segment in 2010. We also believe cash flows from operations will be sufficient to cover the costs of operating our refinery and the financing charges incurred under our crude import facility. Should there be a major deterioration in refining margins, our refinery may not generate sufficient cash flows to cover all of the interest and principal payments under our secured loan agreements. As a result, we may be required to raise additional capital and/or refinance these facilities in the future.

#### *Midstream - Liquefaction*

We and our current joint venture partner in the LNG Project - Pacific LNG Operations Limited, are currently in the process of inviting bids from industry majors and other interested parties to participate in the LNG Project as a joint venture partner.

Completion of any liquefaction facility will require substantial amounts of financing and construction will take a number of years to complete. As a joint venture partner in the project, if the project proceeds, we would be required to fund our share of the development costs. No assurances can be given that we will be able to source sufficient gas, successfully construct such a facility, or as to the timing of such construction. The availability and cost of capital is highly dependent on market conditions at the time we raise such capital.

#### *Downstream*

We believe on the basis of current market conditions and the status of our business that our cash flows from operations will be sufficient to meet our estimated capital expenditures for our wholesale and retail distribution business segment for 2010.

We can provide no assurances that we will be able to obtain additional capital required for our development plans, or that our lenders will agree to refinance our working capital facilities, or, if available, that the terms of any such capital raising or refinancing will be acceptable to us, particularly given the current market conditions.

### **Contractual Obligations and Commitments**

The following table contains information on payments for contracted obligations due for each of the next five years and thereafter. It should be read in conjunction with our audited financial statements for the year ended December 31, 2009 and the notes thereto:

Contractual obligations (\$ thousands)	Payments Due by Period (\$ thousands)						
	Total	Less than 1 year	1 - 2 years	2 - 3 years	3 - 4 years	4 - 5 years	More than 5 years
Secured loan <sup>(3)</sup>	53,500	9,000	9,000	9,000	9,000	9,000	8,500
Indirect participation interest <sup>(1)</sup>	1,384	540	844	-	-	-	-
PNG LNG Inc. Joint Venture (proportionate share of commitments)	35	28	7	-	-	-	-
Petroleum prospecting and retention licenses <sup>(2)</sup>	83,000	4,500	9,500	20,000	14,850	34,150	-
<b>Total</b>	<b>137,919</b>	<b>14,068</b>	<b>19,351</b>	<b>29,000</b>	<b>23,850</b>	<b>43,150</b>	<b>8,500</b>

(1) These amounts represent the estimated cost of completing our commitment to drill exploration wells under our indirect participation interest agreement entered into in July 2003 (Indirect Participation Interest - PNGDV). See Note 20 to our audited financial statements for the year ended December 31, 2009.

(2) The amount pertaining to the petroleum prospecting and retention licenses represents the amount we have committed as a condition on renewal of these licenses. Of this \$83.0 million commitment, as at December 31, 2009, management estimates that \$46.3 million would satisfy the commitments in relation to the IPI investors

(3) This excludes the contractual interest payments on the principal amount. The effective interest rate on this loan for the year ended December 31, 2009 was 6.89%. The annual effective interest rate will be applied to the outstanding balance for the contractual interest payment calculation.

## Off Balance Sheet Arrangements

Neither during the year ended, nor as at December 31, 2009, did we have any off balance sheet arrangements or any relationships with unconsolidated entities or financial partnerships.

## Transactions with Related Parties

Petroleum Independent and Exploration Corporation, a company owned by Mr. Mulacek, our Chairman and Chief Executive Officer, earned management fees of \$150,000 during the year ended December 31, 2009 (December 2008 - \$150,000). This management fee relates to Petroleum Independent and Exploration Corporation acting as the General Manager of one of our subsidiaries, S.P. InterOil LDC, in compliance with OPIC loan requirements.

## Share Capital

Our authorized share capital consists of an unlimited number of common shares and unlimited number of preferred shares, of which 1,035,554 series A preferred shares are authorized. As of December 31, 2009, we had 43,545,654 common shares (45,957,701 common shares on a fully diluted basis) and no preferred shares outstanding. The dilutive instruments outstanding as at December 31, 2009 includes employee stock options in respect of 1,879,900 common shares, IPI conversion rights to 527,147 common shares, and 5,000 common shares that can be exchanged by Petroleum Independent and Exploration Corporation at any time for the remaining 5,000 shares it holds in our subsidiary, S.P. InterOil LDC.

## Derivative Instruments

Our revenues are derived from the sale of refined products. Prices for refined products and crude feedstocks can be volatile and sometimes experience large fluctuations over short periods of time as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions. Due to the nature of our business, there is always a time difference between the purchase of a crude feedstock and its arrival at the refinery and the supply of finished products to the various markets.

Generally, we purchase crude feedstock two months in advance, whereas the supply/export of finished products will take place after the crude feedstock is discharged and processed. Due to the fluctuation in prices during this period, we use various derivative instruments as a tool to reduce the risks of changes in the relative prices of our crude feedstocks and refined products. These derivatives, which we use to manage our price risk, effectively

enable us to lock-in the refinery margin such that we are protected in the event that the difference between our sale price of the refined products and the acquisition price of our crude feedstocks contracts is reduced. Conversely, when we have locked-in the refinery margin and if the difference between our sales price of the refined products and our acquisition price of crude feedstocks expands or increases, then the benefits would be limited to the locked-in margin

The derivative instrument which we generally use is the over-the-counter (OTC) swap. The swap transactions are concluded between counterparties in the derivatives swaps market, unlike futures which are transacted on the International Petroleum Exchange ("IPE") and Nymex Exchanges. We believe these hedge counterparties to be credit worthy. However, given the financial and credit market crisis, the creditworthiness of our hedge counterparties could change quickly. It is common place among refiners and trading companies in the Asia Pacific market to use derivatives swaps as a tool to hedge their price exposures and margins. Due to the wide usage of derivatives tools in the Asia Pacific region, the swaps market generally provides sufficient liquidity for the hedging and risk management activities. The derivatives swap instrument covers commodities or products such as jet and kerosene, diesel, naphtha, and also bench-mark crudes such as Tapis and Dubai. Using these tools, we actively engage in hedging activities to lock in margins. Occasionally, there is insufficient liquidity in the crude swaps market and we then use other derivative instruments such as Brent futures on the IPE to hedge our crude costs.

At December 31, 2009, we had a net receivable of \$nil (December 2008 – net receivable of \$31.3 million) relating to commodity hedge contracts. The total 2008 net receivable related to \$16.3 million of hedge accounted contracts and \$15.1 million of outstanding derivative contracts for which hedge accounting was not applied or had been discontinued. There were no commodity hedge contracts outstanding as at December 31, 2009.

The gain on hedges for which final pricing will be determined in future periods was \$nil (December 2008 - \$18.0 million) and has been included in comprehensive income. The hedges that have resulted in a gain being included within comprehensive income at December 31, 2009 were settled in January 2009. However, these gains have been fully released into the Statement of Operations as the anticipated transactions that these hedges were initially taken to cover have occurred.

A profit of \$17.2 million was recognized from the effective portion of priced out hedge accounted contracts for the year ended December 31, 2009 (December 2008 – profit of \$3.7 million), and a profit of \$1.0 million was recognized on the non-hedge accounted derivative contracts and the ineffective portion of hedge accounted contracts for the year ended December 31, 2009 (December 2008 – profit of \$24.0 million).

## **INDUSTRY TRENDS AND KEY EVENTS**

---

### **Competitive Environment and Regulated Pricing**

We are currently the sole refiner of hydrocarbons in Papua New Guinea under our 30 year agreement with the Papua New Guinea Government, which expires in 2035. The government has undertaken to ensure that all domestic distributors purchase their refined petroleum products from our refinery, or any other refinery which is constructed in Papua New Guinea, at an Import Parity Price ("IPP"). The IPP is monitored by the Papua New Guinea Independent Consumer and Competition Commission ("ICCC"). In general, the IPP is the price that would be paid in Papua New Guinea for a refined product being imported. For all price controlled products (diesel, unleaded petrol, kerosene and aviation gas) produced and sold locally in Papua New Guinea, the IPP is calculated by adding the costs that would typically be incurred to import such product to the posted price for such product in Singapore. In November 2007, the IPP was modified by changing the Singapore benchmark price from the "Singapore Posted Prices" which is no longer being updated, to "Mean of Platts Singapore" ("MOPS") which is the benchmark price for refined products in the region in which we operate. The revised formula is yet to be formally entrenched by means of necessary amendment to the Project Agreement governing the Company's relationship with the Independent State of Papua New Guinea. However, it is the current IPP calculation mechanism being monitored by the ICCC.

We are also a significant participant in the retail and wholesale distribution business in Papua New Guinea. The ICCC regulates the maximum prices that may be charged by the wholesale and retail hydrocarbon distribution industry in Papua New Guinea. Our Downstream business may charge less than the maximum margin set by the ICCC in order to maintain its competitiveness with other participants in the market. In June 2009, ICCC commenced a review into the pricing arrangements for petroleum products in PNG. The last such review was undertaken during 2004 and was due to expire on December 31, 2009. The purpose of the review is to consider the extent to which the existing regulation of price setting arrangements at both wholesale and retail levels should continue or be revised for the next five year period. We have provided detailed submissions to the ICCC. The ICCC have most recently advised that its final report will be issued in March 2010. It is possible that the ICCC may determine to increase regulation of pricing and reduce the margins able to be obtained by our distribution business. Such a decision, if made, may negatively affect our downstream business and require a review of its operations.

### **Credit Crisis and Financing Arrangements**

During 2008 and 2009 the U.S. and other world economies were in recession and the financial and credit markets were significantly disrupted. Many financial institutions had liquidity concerns prompting intervention from governments. These resulted in a reduced capacity of the financial institutions to finance new projects and renew existing facilities with their clients. However, the crisis seems to have bottomed out in the third quarter of 2009 with most major economies starting to see growth by the end of 2009. We continue to monitor liquidity risk through our level of acceptable gearing where we are actively managing the gearing levels as required to manage risk whilst optimizing shareholder returns.

Our aim is to maintain our debt-to-capital ratio, or gearing levels, (long term debt/(shareholders' equity + long term debt)) at 50% or less, and had achieved this objective throughout 2009. Gearing levels were reduced to 11% in December 2009 from 36% in December 2008. This reduction in gearing levels as at December 31, 2009 as compared to December 31, 2008 was mainly due to the conversion during the period from July 2009 to June 2009 of the remaining \$65 million outstanding of the \$95.0 million 8% convertible subordinated debenture completed in May 2008, plus the registered direct offering completed in June 2009 for 2,013,815 common shares to a number of institutional investors at a purchase price of \$34.98 per share raising \$70.4 million.

In 2008, we filed a short form base shelf prospectus with the Ontario Securities Commission and a corresponding registration statement on Form F-10/A with the SEC pursuant to the multi-jurisdictional disclosure system. These filings were made to provide us with financial flexibility in the future and allow us to issue, from time to time until September 2010, up to an aggregate of \$129.6 million of securities in one or more offerings. These securities may be debt securities, common shares, preferred shares, warrants or a combination thereof.

We have a short term total working capital facility of \$190.0 million for our Midstream – Refining operation that is renewable annually with BNP Paribas. As part of the renewal process completed in the quarter ended December 31, 2009, the facility was renewed for a period of fifteen months ending December 31, 2010. The facility is fully secured against trade debtors, inventory and cash deposits. The BNP working capital facility is split into two categories, namely Facility 1 and Facility 2, with their respective sub-limits and restricted usage for each of these components (refer to note 16 in our consolidated financial statements for further information on the split between the two facilities). Our association with BNP Paribas began in 2004 with the working capital facility and has expanded over time to include certain other aspects of our business including managing our hedging trades. See "Liquidity and Capital Resources – Summary of Debt Facilities".

In 2008 we secured a \$55.5 million (Papua New Guinea Kina 150.0 million) revolving working capital facility for our Downstream operations in Papua New Guinea from Bank of South Pacific Limited and Westpac Bank PNG Limited. The Westpac facility limit is Papua New Guinea Kina 80.0 million (approximately \$29.6 million) and is for an initial term of three years and is due for renewal in October 2011. The BSP facility limit is Papua New Guinea Kina 70.0 million (approximately \$25.9 million) is renewable annually and was renewed in October 2009 at a lower limit of Papua New Guinea Kina 50.0 million (approximately \$18.5 million). See "Liquidity and Capital Resources – Summary of Debt Facilities".

We had cash, cash equivalents and cash restricted of \$75.8 million as at December 31, 2009, of which \$29.3 million was restricted (as governed by BNP working capital facility utilization requirements and OPIC secured

loan facility). With regard to our cash and cash equivalents, we invest in bankers acceptances and money market instruments with major financial institutions that we believe are creditworthy. We also had \$116.5 million of the combined BNP working capital facility available for use in our Midstream – Refining operations, and \$36.6 million of the Westpac/BSP combined working capital facility available for use in our Downstream operations.

## **Crude Prices**

Crude prices were less volatile throughout 2009 as compared to 2008, with the price of Tapis crude oil (as quoted by the Asian Petroleum Price Index (“APPI”)) starting the year at \$39/bbl, and on an increasing trend throughout the year closing at \$79/bbl. Tapis is the benchmark for setting crude prices within the region where we operate and is used by us when we purchase crude feedstock for our refinery. The price of Tapis during 2009 averaged \$66/bbl compared to \$101/bbl during 2008.

The decrease in average crude prices during the year has reduced our utilization of our working capital facilities. As noted above, we had as at year end \$116.5 million of the combined BNP working capital facility available for use in our Midstream – Refining operations, and approximately \$36.6 million of the Westpac/BSP combined working capital facility available for use in our Downstream operations. Any increase in prices will have an impact on the utilization of our working capital facilities, and related interest and financing charges on the utilized amounts.

The high volatility of crude prices in 2008 meant that we faced significant timing and margin risk on our crude cargos during that year. A significant portion of this timing and margin risk was managed by us through short and long term hedges that were put in place during the year. We believe our hedge counterparties to be creditworthy. The number of hedges in place declined in 2009 with a reduction in the volatility in prices. There were no outstanding hedge accounted contracts or non-hedged derivative contracts on which final pricing was to be determined in future periods as at December 31, 2009.

## **Refining Margin**

The distillation process used by our refinery to convert crude feedstocks into refined products is commonly referred to as hydroskimming. While the Singapore Tapis hydroskimming margin is a useful indicator of the general margin available for hydroskimming refineries in the region in which we operate, it should be noted that the differences in our approach to crude selection, transportation costs and IPP pricing work to assist our refinery in generally outperforming the Singapore Tapis hydroskimming margin. Therefore, our refinery realizes additional margins due to its niche location when compared to the benchmark for the region.

The volatility of Singapore Tapis hydroskimming margins decreased during 2009, and margins are generally improved in comparison with the previous year.

Distillate margins remained weak in 2009 compared with historical levels due to lower demand and new refining capacity coming on stream in the region. This has adversely affected the gross refining margins on finished products achieved by the refining industry in general.

## **Domestic Demand**

Sales results for our refinery for 2009 indicate that Papua New Guinea’s domestic demand for middle distillates (which includes diesel and jet fuels) from the refinery has stayed fairly constant compared to 2008. The total volume of all products sold by us in the Papua New Guinea was 6.5 million barrels for fiscal year 2009 compared with 6.6 million barrels in 2008.

The refinery on average sold 10,933 bbls/day of refined petroleum products to the domestic market during fiscal year 2009 compared with 10,888 bbls/day in 2008.

## Interest Rates

The LIBOR USD overnight rate is the benchmark floating rate used in our midstream working capital facility and therefore accounts for a significant proportion of our interest rate exposure. The LIBOR USD overnight rate has decreased from around 0.6% in early 2009 to 0.2% by the end of 2009, which was in line with underlying U.S. Federal Reserve rate cuts. Any rate increases would add additional cost to financing our crude cargoes and vice versa as our BNP Paribas working capital facility is linked to LIBOR rates. See “Liquidity and Capital Resources – Summary of Debt Facilities”.

## Exchange Rates

Changes in the Papua New Guinea Kina (“PGK”) to USD exchange rate can affect our Midstream Refinery results as there is a timing difference between the foreign exchange rates utilized when setting the monthly IPP, which is set in PGK, and the foreign exchange rate used to convert the subsequent receipt of PGK proceeds to USD to repay our crude cargo borrowings. The PGK weakened against the USD during the three months ended March 31, 2009 (from 0.3735 to 0.3400). However, it has since strengthened against the USD during the nine months ended December 31, 2009 (from 0.3400 to 0.3700).

## RISK FACTORS

---

Our business operations and financial position are subject to a range of risks. A summary of the key risks that may impact upon the matters addressed in this document have been included under section “Legal Notice – Risk Factors and Forward Looking Statements” above. Detailed risk factors can be found under the heading “*Risk Factors*” in our 2009 Annual Information Form available at [www.sedar.com](http://www.sedar.com).

## CRITICAL ACCOUNTING ESTIMATES

---

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. The following accounting policies involve estimates that are considered critical due to the level of sensitivity and judgment involved, as well as the impact on our consolidated financial position and results of operations. The information about our critical accounting estimates should be read in conjunction with Note 2 of the notes to our consolidated financial statements for the year ended December 31, 2009, available at [www.sedar.com](http://www.sedar.com) which summarizes our significant accounting policies.

### *Income Taxes*

We use the asset and liability method of accounting for income taxes. Under the asset and liability method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment. A valuation allowance is provided against any portion of a future tax asset which will more than likely not be recovered. In considering the recoverability of future tax assets and liabilities, we consider a number of factors, including the consistency of profits generated from the refinery, likelihood of production from Upstream operations to utilize the carried forward exploration costs, etc. If actual results differ from the estimates or we adjust the estimates in future periods, we may need to record a valuation allowance. The net deferred income tax assets as of December 31, 2009 and 2008 were \$16.9 million and \$3.1 million, respectively.

### *Oil and Gas Properties*

We use the successful-efforts method to account for our oil and gas exploration and development activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. We continue to carry as an asset the cost of drilling exploratory wells if the required capital expenditure is made and drilling of additional exploratory wells is underway or firmly planned for the near future, or when exploration and evaluation activities have not yet reached a stage to allow reasonable assessment regarding the existence of economical reserves. Capitalized costs for producing wells will be subject to depletion using the units-of-production method. Geological and geophysical costs are expensed as incurred. If our plans change or we adjust our estimates in future periods, a reduction in our oil and gas properties asset will result in a corresponding increase in the amount of our exploration expenses.

### *Asset Retirement Obligations*

Estimated costs of future dismantlement, site restoration and abandonment of properties are provided based upon current regulations and economic circumstances at year end. Management estimates there are no material obligations associated with the retirement of the refinery or with its normal operations relating to future restoration and closure costs. The refinery is located on land leased from the Independent State of Papua New Guinea. The lease expires on July 26, 2097. Future legislative action and regulatory initiatives could result in changes to our operating permits which may result in increased capital expenditures and operating costs.

### *Environmental Remediation*

Remediation costs are accrued based on estimates of known environmental remediation exposure. Ongoing environmental compliance costs, including maintenance and monitoring costs, are expensed as incurred. Provisions are determined on an assessment of current costs, current legal requirements and current technology. Changes in estimates are dealt with on a prospective basis. We currently do not have any amounts accrued for environmental remediation obligations. Future legislative action and regulatory initiatives could result in changes to our operating permits which may result in increased capital expenditures and operating costs.

### *Impairment of Long-Lived Assets*

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, and goodwill for potential impairment. We test long-lived assets for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. In order to determine fair value, our management must make certain estimates and assumptions including, among other things, an assessment of market conditions (including estimation of gross refining margins, crude price environments and its impact on IPP, etc), projected cash flows, investment rates, interest/equity rates and growth rates, that could significantly impact the fair value of the asset being tested for impairment. Due to the significant subjectivity of the assumptions used to test for recoverability and to determine fair value, changes in market conditions could result in significant impairment charges in the future, thus affecting our earnings. Our impairment evaluations are based on assumptions that are consistent with our business plans.

### *Legal and Other Contingent Matters*

We are required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can reasonably be estimated. When the amount of a contingent loss is determined it is charged to earnings. Our management continually monitors known and potential contingent matters and makes appropriate provisions by charges to earnings when warranted by circumstances.

## **NEW ACCOUNTING STANDARDS**

---

### **Standards adopted effective January 1, 2009**

Effective year ended December 31, 2009, the Company adopted the revisions to CICA 3862 – Financial Instruments – Disclosures which was amended to include additional disclosure requirements about fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements for publicly accountable enterprises. The revisions require the disclosure of maturity analysis for derivative and non-derivative financial assets and liabilities, and additional information on liquidity risk. The Company has made these additional disclosures within notes 3(b) Liquidity risk, and note 3(g) Fair values.

Based on the detailed review conducted by the Company of the new CICA sections, or revisions to current sections, no other items have been identified as having any material impact on the Company's financial statements.

### **New Accounting standards not yet applicable as at December 31, 2009**

Based on the detailed review conducted by the Company of the new CICA sections, or revisions to current sections, that are effective for the year beginning January 1, 2010, no items have been identified as having any material impact on the Company's financial statements.

The Accounting Standards Board ("AcSB") has announced its intention to adopt International Financial Reporting Standards ("IFRS") as Canadian GAAP, effective January 1, 2011. In anticipation of the change, the AcSB is revising certain Canadian accounting standards to conform to IFRS in advance of the 2011 implementation date. The required change to IFRS is mandatory for all Canadian publicly accountable entities, which includes those with public debt.

The SEC currently allows foreign private issuers using IFRS as their primary GAAP to not provide reconciliation to U.S. GAAP in their financial statements.

We will adopt IFRS as per the guidelines issued by AcSB and report under IFRS effective January 1, 2011 with comparative IFRS numbers for 2010.

We have an IFRS Steering Committee working under the oversight of the Audit Committee monitoring the IFRS transition plan. Based on the work performed on evaluating key differences between Canadian GAAP and IFRS as applicable to us, no major differences have yet been noted that would have any significant effect on transition to IFRS. As a result of this assessment, we do not expect that there will be a significant impact on us in relation to our systems and internal controls.

We will continue to monitor the revisions being made by AcSB to the Canadian accounting standards to conform to IFRS in advance of the 2011 implementation date. Any revisions that will result in a change in the accounting policy of InterOil, on adoption of IFRS effective January 1, 2011, will be disclosed as policy changes in the financial statements.

The areas in which we anticipate revisions to accounting standards prior to the IFRS adoption date of January 1, 2011 that may affect InterOil's accounting policies are:

- Oil and Gas industry specific accounting under IFRS or Canadian GAAP is currently not as comprehensive as the guidance provided under U.S. GAAP accounting for industry specific oil and gas transactions. International Accounting Standards Board ("IASB") has commenced a project to publish guidelines on accounting for oil and gas transactions, which may be different from the current guidelines under U.S. GAAP.
- Section 3055 - Joint Venture Interests under Canadian GAAP differs from similar guidance under IAS 31 as IAS 31 permits the use of either the proportionate consolidation method or the equity method to account for joint ventures. IASB has commenced a project to remove the option for accounting for interests in jointly

controlled entities using the proportionate consolidation method. InterOil currently uses proportionate consolidation for accounting for the LNG joint venture under Canadian GAAP, and equity accounting for the same under U.S. GAAP.

- Other areas that are being monitored include property plant and equipment measurement and impairment, measurement and recognition of provisions, enterprises in development stage, and the optional exemptions available under IFRS 1 which provides a mandatory framework for first time adopters which supersedes the transitional provisions of individual standards.

## NON-GAAP MEASURES AND RECONCILIATION

Gross Margin is a non-GAAP measure and is “sales and operating revenues” less “cost of sales and operating expenses”. The following table reconciles sales and operating revenues, a GAAP measure, to Gross Margin:

Consolidated – Operating results (\$ thousands)	Year ended December 31,		
	2009	2008	2007
Midstream – Refining	574,409	786,114	523,817
Downstream	388,991	556,868	391,738
Corporate	21,194	24,567	9,482
Consolidation Entries	(296,115)	(451,970)	(299,511)
<b>Sales and operating revenues</b>	<b>688,479</b>	<b>915,579</b>	<b>625,526</b>
Midstream – Refining	(516,349)	(779,832)	(495,059)
Downstream	(359,623)	(536,920)	(368,803)
Corporate <sup>(1)</sup>	-	-	-
Consolidation Entries	273,989	428,129	290,253
<b>Cost of sales and operating expenses</b>	<b>(601,983)</b>	<b>(888,623)</b>	<b>(573,609)</b>
Midstream – Refining	58,060	6,282	28,758
Downstream	29,368	19,948	22,935
Corporate <sup>(1)</sup>	21,194	24,567	9,482
Consolidation Entries	(22,126)	(23,841)	(9,258)
<b>Gross Margin</b>	<b>86,496</b>	<b>26,956</b>	<b>51,917</b>

(1) Corporate expenses are classified below the gross margin line and mainly relates to ‘Office and admin and other expenses’ and ‘Interest expense’.

EBITDA represents our net income/(loss) plus total interest expense (excluding amortization of debt issuance costs), income tax expense, depreciation and amortization expense. EBITDA is used by us to analyze operating performance. EBITDA does not have a standardized meaning prescribed by United States or Canadian generally accepted accounting principles and, therefore, may not be comparable with the calculation of similar measures for other companies. The items excluded from EBITDA are significant in assessing our operating results. Therefore, EBITDA should not be considered in isolation or as an alternative to net earnings, operating profit, net cash provided from operating activities and other measures of financial performance prepared in accordance with GAAP. Further, EBITDA is not a measure of cash flow under GAAP and should not be considered as such. For reconciliation of EBITDA to the net income (loss) under GAAP, refer to the following table.

The following table reconciles net income (loss), a GAAP measure, to EBITDA, a non-GAAP measure for each of the last eight quarters.

Quarters ended (\$ thousands)	2009				2008			
	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31
Upstream	574	(29,097)	(669)	(469)	(2,483)	231	10,164	(1,135)
Midstream – Refining	8,492	8,199	14,134	14,747	(13,976)	17,516	16,329	5,724
Midstream – Liquefaction	(1,200)	(2,119)	(1,379)	(2,361)	(2,501)	(1,570)	(1,784)	(1,636)
Downstream	4,391	6,542	4,150	3,241	(7,244)	610	7,893	4,529
Corporate	1,765	1,980	1,897	3,051	226	764	(2,155)	1,796
Consolidation Entries	(4,884)	(4,092)	(278)	(7,285)	(2,866)	(736)	(3,092)	(2,143)
<b>Earnings before interest, taxes, depreciation and amortization</b>	<b>9,138</b>	<b>(18,587)</b>	<b>17,855</b>	<b>10,924</b>	<b>(28,844)</b>	<b>16,815</b>	<b>27,355</b>	<b>7,135</b>
<b>Subtract:</b>								
Upstream	(4,056)	(2,164)	(1,563)	(1,552)	(1,345)	(1,137)	(841)	(704)
Midstream – Refining	(1,973)	(1,682)	(1,709)	(1,786)	(2,771)	(2,113)	(2,263)	(2,761)
Midstream – Liquefaction	(379)	(348)	(333)	(158)	(65)	(63)	(60)	(53)
Downstream	(930)	(1,045)	(1,013)	(1,142)	(2,232)	(885)	(715)	(1,005)
Corporate	(27)	0	(1,600)	(2,325)	(2,320)	(2,484)	(2,871)	(3,091)
Consolidation Entries	5,905	3,823	3,141	2,923	2,866	2,633	1,824	2,424
<b>Interest expense</b>	<b>(1,460)</b>	<b>(1,416)</b>	<b>(3,077)</b>	<b>(4,040)</b>	<b>(5,867)</b>	<b>(4,049)</b>	<b>(4,926)</b>	<b>(5,190)</b>
Upstream	-	-	-	-	-	-	-	-
Midstream – Refining	14,316	-	-	-	-	-	-	-
Midstream – Liquefaction	(8)	(3)	(32)	(12)	(12)	(25)	(49)	(24)
Downstream	(411)	(1,398)	(733)	(485)	4,297	83	(3,212)	(753)
Corporate	1,340	(339)	(800)	(359)	(163)	(21)	(122)	(81)
Consolidation Entries	(3)	(1)	(2)	(2)	4	(3)	(2)	0
<b>Income taxes and non- controlling interest</b>	<b>15,234</b>	<b>(1,741)</b>	<b>(1,567)</b>	<b>(858)</b>	<b>4,126</b>	<b>34</b>	<b>(3,385)</b>	<b>(858)</b>
Upstream	(144)	(132)	(150)	(112)	(175)	(134)	(135)	(154)
Midstream – Refining	(2,765)	(2,755)	(2,801)	(2,611)	(2,742)	(2,742)	(2,723)	(2,760)
Midstream – Liquefaction	(7)	(10)	(20)	(20)	(19)	(19)	(16)	(15)
Downstream	(679)	(658)	(662)	(651)	(722)	(693)	(582)	(573)
Corporate	(43)	(40)	(174)	(18)	(19)	(18)	(16)	(15)
Consolidation Entries	33	33	32	32	32	33	32	32
<b>Depreciation and amortisation</b>	<b>(3,605)</b>	<b>(3,562)</b>	<b>(3,775)</b>	<b>(3,380)</b>	<b>(3,645)</b>	<b>(3,573)</b>	<b>(3,440)</b>	<b>(3,485)</b>
Upstream	(3,626)	(31,392)	(2,382)	(2,134)	(4,003)	(1,039)	9,188	(1,993)
Midstream – Refining	18,071	3,762	9,624	10,349	(19,490)	12,660	11,345	201
Midstream – Liquefaction	(1,593)	(2,481)	(1,764)	(2,551)	(2,596)	(1,677)	(1,910)	(1,727)
Downstream	2,371	3,440	1,742	964	(5,900)	(886)	3,384	2,197
Corporate	3,034	1,601	(677)	350	(2,276)	(1,759)	(5,164)	(1,390)
Consolidation Entries	1,050	(236)	2,893	(4,332)	35	1,928	(1,239)	314
<b>Net profit/(loss) per segment</b>	<b>19,307</b>	<b>(25,306)</b>	<b>9,436</b>	<b>2,646</b>	<b>(34,230)</b>	<b>9,227</b>	<b>15,604</b>	<b>(2,398)</b>

- (1) The inter-company interest charges have been restated for quarter ended March 31, 2008 and June 30, 2008 to reflect transfer of certain inter-company loan balances to inter-company investments.
- (2) During the year, the Company has transferred notional interest cost from Corporate segment to the Upstream and Midstream – Liquefaction segments to reflect a more accurate view of its segment results. The prior year comparatives have been reclassified to conform to the current classification.

## **PUBLIC SECURITIES FILINGS**

---

You may access additional information about us, including our Annual Information Form for the year ended December 31, 2009, in documents filed with the Canadian Securities Administrators at [www.sedar.com](http://www.sedar.com), and in documents, including our Form 40-F, filed with the U.S. Securities and Exchange Commission at [www.sec.gov](http://www.sec.gov). Additional information is also available on our website [www.interoil.com](http://www.interoil.com).

## **DISCLOSURE CONTROLS AND PROCEDURES**

---

The Company has implemented disclosure controls and procedures, as defined in National Instrument 52-109-Certification of Disclosure in Issuer's Annual and Interim Filings ("NI 52-109"), to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management, as appropriate, to allow timely decisions regarding required disclosures. Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting.

The Company's internal control system was designed to provide reasonable assurance that all transactions are accurately recorded, that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that the Company's assets are safeguarded. Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedure may deteriorate.

The CEO and CFO are required to certify on the effectiveness of the Company's disclosure controls and procedures and internal controls over financial reporting concurrent with filing its financial statements for the year ended December 31, 2009 in accordance with NI 52-109. The Company's CEO and CFO, together with management, have concluded, based on their evaluation of the effectiveness of the Company's disclosure controls and procedures as of December 31, 2009, that information required to be disclosed by the Company is (i) recorded, processed, summarized and reported within the time periods specified in Canadian securities legislation and (ii) accumulated and communicated to the Company's management, including its CEO and CFO, to allow timely decisions regarding required disclosure.

### **Internal Control Over Financial Reporting**

The CEO and the CFO have also evaluated the effectiveness of InterOil's internal controls over financial reporting ("ICFR") as at December 31, 2009. During the year ended December 31, 2009, there were no material changes in the Company's disclosure controls and procedures or ICFR. InterOil's ICFR are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. However, because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. In making their evaluation, the CEO and CFO used the criteria set forth in the framework established by the Committee of Sponsoring Organizations ("COSO") entitled – Internals Controls – Integrated Framework. Based on their evaluation, the CEO and CFO concluded that our ICFR are effective to provide reasonable assurance with respect to the objectives of our ICFR.

## GLOSSARY OF TERMS

---

**Barrel, Bbl** Unit volume measurement used for petroleum and its products, equivalent to 42 U.S. gallons.

**BNP Paribas** BNP Paribas Capital (Singapore) Limited.

**BP** BP Singapore Pte Limited.

**Condensate** A component of natural gas which is a liquid at surface conditions.

**Crack spread** The simultaneous purchase or sale of crude against the sale or purchase of refined petroleum products. These spread differentials which represent refining margins are normally quoted in dollars per barrel by converting the product prices into dollars per barrel and subtracting the crude price.

**Crude Oil** A mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

**EBITDA** Earnings before interest, taxes, depreciation and amortization. EBITDA represents net income/(loss) plus total interest expense (excluding amortization of debt issuance costs), income tax expense, depreciation and amortization expense. EBITDA is used to analyze operating performance.

**Feedstock** Raw material used in a processing plant.

**GAAP** Generally accepted accounting principles.

**Gas** A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

**ICCC** Independent Consumer and Competition Commission. The statutory competition authority in Papua New Guinea.

**IPP** Import Parity Price. For each refined product produced and sold locally in Papua New Guinea, IPP is calculated by adding the costs that would typically be incurred to import such product to the average posted price for such product in Singapore as reported by Platts. The costs that are added to the reported Platts price include freight costs, insurance costs, landing charges, losses incurred in the transportation of refined products, demurrage and taxes.

**IPI** Indirect Participation Interest. These interests are held by various investors pursuant to participation interest agreements entered into in 2003, 2004 and 2005 and identified more fully in our Annual Information Form.

**Joint Venture Company** or **PNG LNG** means PNG LNG, Inc., a joint venture company established in 2007 by InterOil LNG Holdings Inc., an affiliate of InterOil, MLPLC, an affiliate of Merrill Lynch, and PacLNG to construct the proposed LNG plant. Under an agreement reached in February 2009, MLPLC no longer holds any interest in PNG LNG.

**LIBOR** Daily reference rate based on the interest rates at which banks borrow unsecured funds from banks in the London wholesale money market.

**LNG** Liquefied natural gas. Natural gas converted to a liquid state by pressure and severe cooling, and then returned to a gaseous state to be used as fuel. LNG is moved in tankers, not via pipelines. LNG, which is predominantly artificially liquefied methane, is not to be confused with NGLs, natural gas liquids, which are heavier fractions that occur naturally as liquids

**LNG Project** The potential development by us of a liquefied natural gas processing facility in Papua New Guinea described as our Midstream Liquefaction business segment and being undertaken as a joint venture with Pacific LNG Operations Ltd through a joint venture company PNG LNG Inc.

**LSWR** Low Sulphur Waxy Residue.

**Naphtha** That portion of the distillate obtained in the refinement of petroleum which is an intermediate between the lighter gasoline and the heavier benzene, has a specific gravity of about 0.7, and is used as a solvent for varnishes, illuminant, and other similar products.

**Natural gas** A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

**PGK** the Kina, Currency of Papua New Guinea.

**PPL** Petroleum Prospecting License. The tenement given by the State to explore for oil and gas.

**PRL** Petroleum Retention License. The tenement given by the Independent State of Papua New Guinea to allow the licensee holder to evaluate the commercial and technical options for the potential development of an oil and/or gas field.

**State** or **PNG** means the Independent State of Papua New Guinea.

**USD** United States Dollars.

**Working interest** An interest in a mineral property that entitles the owner of such interest to a share of the mineral productions from the property with the share based on such owner's relative interest.

**Mcf** Standard abbreviation for 1,000 cubic feet.

**Bil cu ft** Billion cubic feet. Also abbreviated to bcf.

**Tcf** Trillion cubic feet.