

# InterOil Corporation Management Discussion and Analysis

For the Year ended December 31, 2010  
March 22, 2011



## TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS .....	2
OIL AND GAS DISCLOSURES.....	4
INTRODUCTION .....	4
BUSINESS STRATEGY.....	5
OPERATIONAL HIGHLIGHTS.....	5
SELECTED ANNUAL FINANCIAL INFORMATION AND HIGHLIGHTS .....	8
YEAR AND QUARTER IN REVIEW.....	15
LIQUIDITY AND CAPITAL RESOURCES.....	23
INDUSTRY TRENDS AND KEY EVENTS .....	31
RISK FACTORS .....	33
CRITICAL ACCOUNTING ESTIMATES.....	34
NEW ACCOUNTING STANDARDS.....	35
NON-GAAP MEASURES AND RECONCILIATION .....	37
PUBLIC SECURITIES FILINGS.....	39
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING .....	39
GLOSSARY OF TERMS.....	39

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, 2010 and our annual information form for the year ended December 31, 2010 (the “2010 Annual Information Form”). The MD&A was prepared by management and provides a review of our performance in the year ended December 31, 2010, 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, 2010, unless otherwise specified.

We are not presenting all information in this MD&A in accordance with U.S. GAAP. Readers should review Note 31 - “Reconciliation to the generally accepted accounting principles in the United States” to the audited financial statements for the year ended December 31, 2010 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 proposed liquefaction facilities and condensate stripping facilities in Papua New Guinea; the development of such liquefaction and condensate stripping facilities; 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 liquefaction and condensate stripping facilities;*
- *our ability to negotiate final definitive agreements contemplated by the Heads of Agreement with Energy World Corporation, Ltd;*
- *the uncertainty on the availability, terms and deployment of capital;*
- *our ability to construct and commission our liquefaction and condensate stripping facilities together with the construction of the common facilities and pipelines, on time and within budget;*
- *the inherent uncertainty of oil and gas exploration activities;*
- *the availability of crude feedstock at economic rates;*
- *the uncertainty associated with the regulated prices at which our products may be sold;*
- *difficulties with the recruitment and retention of qualified personnel;*
- *losses from our hedging activities;*
- *fluctuations in currency exchange rates;*
- *risks of legal action against us*
- *political, legal and economic risks in Papua New Guinea;*
- *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 adverse effects from importation of competing products contrary to our legal rights;*
- *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.*
- *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;*
- *general economic conditions, including any further economic downturn and the availability of credit;*
- *actions by our joint venture partners;*
- *the impact of our current debt on our ability to obtain further financing; 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 Annual Information Form for the year ended December 31, 2010.

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 to 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, 2010 in accordance with NI 51-101, which evaluation is summarized in our 2010 Annual Information Form available at [www.sedar.com](http://www.sedar.com). We do not have any production or reserves, including proved reserves, as defined under NI 51-101 or as per the guidelines set by the United States Securities and Exchange Commission ("SEC"), as at December 31, 2010.

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.

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 thousand cubic feet 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 fully integrated energy company operating in Papua New Guinea and its surrounding region. Our operations are organized into four major segments:

Segments	Operations
<b>Upstream</b>	<b>Exploration and Production</b> – Explores, appraises and develops crude oil and natural gas structures in Papua New Guinea. Currently developing the Elk Antelope infrastructure which includes condensate stripping and associated facilities, and the gas gathering and associated common facilities, in connection with commercializing significant gas discoveries.
<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> – The LNG Project. Developing liquefaction and associated facilities in Papua New Guinea for the export of LNG.
<b>Downstream</b>	<b>Wholesale and Retail Distribution</b> – Markets and distributes refined 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 strategy is to develop a vertically integrated energy company in Papua New Guinea and the surrounding region, 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 we operate. A significant current element of that strategy is to develop gas liquefaction and condensate stripping facilities in Papua New Guinea and to establish gas and gas condensate reserves. We are aiming to pursue this strategy by:

InterOil plans to achieve this strategy by:

- Developing our position as a prudent and responsible business operator;
- Enhancing the existing refining and distribution business;
- Maximizing the value of our exploration assets;
- Monetizing our discovered resources through condensate stripping and liquefaction facilities and businesses; and
- Positioning ourselves for long term success.

Further details of our business strategy can be found under the heading “*Business Strategy*” in our 2010 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 February 9, 2010, we acquired a second drilling rig for approximately \$4.5 million with additional costs incurred for the inspection, package and transport of the rig. The rig was shipped from New Zealand to Papua New Guinea and is currently at our facilities in Napa Napa where upgrades were carried out to prepare the rig for in field drilling within Elk and Antelope fields.
- On April 15, 2010, we entered into a preliminary works joint venture and preliminary works financing agreement with Mitsui & Co. Ltd. (“Mitsui”) to commence Front-End Engineering and Design (“FEED”) work on the proposed CS Project. On August 4, 2010, we finalized a Joint Venture Operating Agreement (“JVOA”) with Mitsui for the CS Project. The capital cost for the CS Project is currently estimated at \$550.0 million, with approximately \$32.0 million of this to be expended for FEED. A Final Investment Decision (“FID”) by the JVOA partners is currently targeted for before June 30, 2011. Mitsui will be responsible for arranging or providing financing for the capital costs of the project in the event that a positive FID is made. An option deed was also executed with Mitsui, under which Mitsui has the option to acquire interests of up to a 5% in the Elk and Antelope fields, and in our proposed LNG Project.
- During the third quarter of 2010, we completed drilling and logging activities on the Antelope 2 well, having drilled a further horizontal section in order to evaluate additional reservoir and test the condensate-to-gas ratio (“CGR”) in the deeper section of the reservoir. Drill Stem Test 7 produced a stabilized CGR of approximately 24.0 to 27.7 barrels of condensate per million cubic feet of natural gas. Subsequently, this well was plugged and suspended for planned future completion as a producer prior to start-up of the proposed condensate stripping and LNG processing facilities.
- During the quarter ended September 30, 2010, the Department of Petroleum and Energy in Papua New Guinea approved the divestment of our 15% non-operated interest in PPL 244.
- During the third quarter of 2010, we finalized the acquisition and processing of 40.8 kilometres of 2D seismic over the Bwata gas field (PPL237 with 20.8 kilometers in 2 dip lines) and the Wolverine prospect (PPL238 with 20 kilometers in 2 dip lines). During the fourth quarter, the seismic program focused on further delineation of Bwata and Wolverine structures, apportioned into 58 km for Bwata (consisting of 3

dip lines and 1 strike line) and 45.4 kilometers for Wolverine (consisting of 3 dip lines and a strike line running north-south). The data is being processed and interpreted.

- At the end of the 2010, the initial preparatory work on a seismic program for PPL 236 were well advanced with social mapping and construction of the base camp initiated. Work on the PPL 236 seismic comprises 70 kilometers comprising 6 dip lines which transect the Whale, Tuna, Barracuda, Wahoo, Mako and Shark leads. The seismic program is expected to be completed in March 2011 and will also fulfil our license commitment for PPL 236.
- On November 30, 2010, we were granted Petroleum Retention License (“PRL”) 15, covering blocks including and surrounding the Elk and Antelope fields, unifying the fields into a single license separate from our exploration acreage and specifying minimum work commitment activities over the next five years. Specific approvals from the Oil and Gas Minister of Papua New Guinea under the PRL or a Petroleum Development License (“PDL”) will be required from the State before commencement of construction or commercial production of hydrocarbons from the license can begin. We have initiated the work on the application and associated information required to be submitted to the State.
- During 2010, we bought back a total of 1.45% of interests held under the 2005 Amended and Restated Indirect Participation Interest Agreement (“IPI Agreement”). In exchange for these interests, we issued 754,788 common shares to those investors which had an aggregate value of \$50.7 million when issued. Our current interest in our exploration licenses after this transaction is 75.6114%, assuming that all remaining IPI investors take up their working interest rights in such licenses and excluding the interests that the State is able to take up under relevant legislation.
- During the last quarter of 2010, we evaluated the seismic results before deciding to drill our next well. During this time, drilling equipment underwent maintenance, and our drilling and associated equipments crew were on standby. All costs in relation to the maintenance and standby time has been expensed, which has increased our exploration costs and office and administration and other expenses within the statement of operations.

#### *Midstream – Refining*

- Total refinery throughput for the year ended December 31, 2010 was 24,682 barrels per operating day, compared with 21,155 barrels per operating day during 2009.
- Capacity utilization for 2010, based on 36,500 barrels per day operating capacity, was 53% compared with 47% in 2009.
- During the years ended December 31, 2010 and 2009, our refinery was shut down for 81 days and 80 days, respectively. During the quarter ended December 31, 2010 and 2009, our refinery was shut down for 40 and 24 days respectively. The higher number of shut down days in the fourth quarter of 2010 was due to the turnaround maintenance which ran from October 1, 2010 to November 2, 2010.
- The catalytic reformer unit which allows the refinery to produce reformat for gasoline remained shut down throughout the year due to technical problems. This shutdown required us to import unleaded gasoline to satisfy domestic needs.

#### *Midstream – Liquefaction*

- On September 28, 2010, we together with Liquid Niugini Gas Ltd., signed a heads of agreement with Energy World Corporation (“EWC”) to construct a three million tonne per annum land based LNG facility in the Gulf Province of Papua New Guinea. Following this agreement, and subsequent to year end, on February 2, 2011, the parties signed certain conditional agreements defining certain parameters for the aforementioned development, construction, financing and the operation of the planned land-based modular LNG facilities. These facilities are intended to be developed in phases.
- Further engineering and planning work was undertaken to design the LNG and condensate facilities, and appropriate supporting infrastructure, including a jetty and loading facilities together with pipelines for both gas and condensate. The wells and processed natural gas pipeline and condensate pipeline from the condensate stripping plant to the coast in the Gulf Province will be the responsibility of the owners of the Elk and Antelope fields, including us and our upstream partners.

#### *Downstream*

- Total Downstream sales volumes for 2010 were 626.5 million liters compared with 588.8 million liters for 2009. Volume growth continued throughout the year, mainly due to increased construction activity in the latter half of the year associated with Exxon Mobil’s LNG project in Papua New Guinea.

- In January 2010, we took delivery of a second charter vessel Saturn, a 13,051 dead weight tones (“DWT”) vessel. This vessel was initially chartered for nine months and during the year the contract was extended until April 2011. Our first charter, the MT Ipsilantis, has also been extended for a further 2 years from March 2011. In June 2010, this vessel was converted from diesel to low sulphur waxy residue (“LSWR”) bunkering fuel. Our vessels now operate exclusively on LSWR.
- During the second quarter of 2010, we finalized the renewal agreement with Ok Tedi Mining Limited for a two year term with estimated volume in excess of 100.0 million liters per annum.
- During the third quarter of 2010, we finalized agreements with Ramu Nico Limited, and certain contractors for the Exxon Mobil LNG project for an estimated volume of 70.0 million liters per annum. PNG Power Ltd also signed an agreement to source an additional 26.0 million liters per annum for a new power generation site in Port Moresby.
- In November 2010, the Papua New Guinea Independent Consumer and Competition Commission (“ICCC”) completed its review of the pricing arrangements for petroleum products in PNG. The purpose of the review was 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 until the end of 2014. The report recommended an increase in margins for wholesaling and certain other activities while the retail margin is to remain the same. It also recommended some increases in monitoring industry activity in PNG.

#### Corporate

- During 2009, we reviewed and selected an Enterprise Resource Planning (“ERP”) system for implementation group-wide. The implementation process for Microsoft Dynamics AX is ongoing and we migrated all businesses and operations, except for Downstream operations, to the new system during 2010. We plan to migrate the downstream business to the new ERP system during the first half of 2011.
- On August 11, 2010, we entered into a short term secured credit facility of \$25.0 million with Clarion Finanz AG (“Clarion”). The funds were made available in two installments of \$12.5 million each on August 11, 2010 and August 30, 2010. The facility was due to mature on January 31, 2011, and carried an interest rate of 10% per annum. This facility was fully repaid in November 2010 from the proceeds of our concurrent public offerings.
- On August 31, 2010, we entered into an agreement to settle and release all claims against us and our subsidiaries brought by various plaintiffs in the District Court of Montgomery County, Texas commenced in 2005 and styled *Todd Peters et al v. Phil Mulacek et. al.* Pursuant to the agreed settlement, on October 19, 2010 we issued 199,677 common shares to the plaintiffs, valued at \$12.0 million based on a volume weighted average price calculated over the ten trading days prior to execution of the settlement agreement. The settlement did not reflect any admission of liability by us.
- On November 5, 2010, we undertook concurrent public offerings of 2,800,000 common shares at an issue price of \$75.00 per share for gross proceeds of \$210.0 million, and \$70.0 million aggregate principal amount of 2.75% convertible senior notes due 2015, raising gross proceeds of \$280.0 million from the combined offerings. The net proceeds after deducting the underwriting discounts, commissions and offering expenses were \$266.0 million.

## SELECTED ANNUAL FINANCIAL INFORMATION AND HIGHLIGHTS

Consolidated Results for the years ended December 31, 2010, 2009 and 2008

Consolidated – Operating results (\$ thousands, except per share data)	Year ended December 31,		
	2010	2009	2008
Sales and operating revenues	802,374	688,479	915,579
Interest revenue	151	351	932
Other non-allocated revenue	4,470	4,228	3,216
<b>Total revenue</b>	<b>806,995</b>	<b>693,058</b>	<b>919,727</b>
Cost of sales and operating expenses	(701,557)	(601,983)	(888,623)
Office and administration and other expenses	(52,650)	(44,894)	(46,691)
Derivative (loss)/gain	(1,065)	1,009	24,039
Exploration costs	(16,982)	(209)	(996)
Exploration impairment	-	-	(108)
Gain on sale of oil and gas properties assets	2,141	7,364	11,235
Loss on extinguishment of IPI liability	(30,569)	(31,710)	-
Litigation settlement expense	(12,000)	-	-
Foreign exchange (loss)/gain	(10,777)	(3,305)	3,878
<b>Earnings before interest, taxes, depreciation and amortization ("EBITDA" - non-GAAP measure) <sup>(1)</sup></b>	<b>(16,464)</b>	<b>19,330</b>	<b>22,461</b>
Depreciation and amortization	(14,275)	(14,322)	(14,143)
Interest expense	(7,364)	(9,993)	(20,032)
<b>Loss before income taxes and non-controlling interest</b>	<b>(38,103)</b>	<b>(4,985)</b>	<b>(11,714)</b>
Income tax (expense)/benefit	(7,383)	11,076	(82)
Non-controlling interest	(7)	(8)	(1)
<b>Net (loss)/profit</b>	<b>(45,493)</b>	<b>6,083</b>	<b>(11,797)</b>
<b>Net (loss)/profit per share (dollars) (basic)</b>	<b>(1.03)</b>	<b>0.15</b>	<b>(0.35)</b>
<b>Net (loss)/profit per share (dollars) (diluted)</b>	<b>(1.03)</b>	<b>0.15</b>	<b>(0.35)</b>
<b>Total assets</b>	<b>965,489</b>	<b>631,754</b>	<b>591,843</b>
<b>Total liabilities</b>	<b>276,967</b>	<b>189,764</b>	<b>364,704</b>
<b>Total long-term liabilities</b>	<b>134,449</b>	<b>96,225</b>	<b>208,224</b>
<b>Gross margin <sup>(2)</sup></b>	<b>100,817</b>	<b>86,496</b>	<b>26,956</b>
<b>Cash flows (used in)/provided by operating activities <sup>(3)</sup></b>	<b>(13,561)</b>	<b>44,500</b>	<b>15,586</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.

### ***Analysis of Financial Condition Comparing Years Ended December 31, 2010, 2009 and 2008***

During the year ended December 31, 2010, we increased our cash holdings and strengthened our financial position with the concurrent public offerings made up of 2,800,000 common shares for gross proceeds of \$210.0 million and \$70.0 million principal amount of 2.75% convertible notes offering, raising gross proceeds of \$280.0 million from the combined offerings. The net proceeds after deducting the underwriting discounts, commissions and offering expenses were \$266.0 million. The funds raised by these concurrent offerings, and the increase in cash and cash equivalents, are designated for use in the development of Elk Antelope Project, CS Project and LNG Project in Papua New Guinea. Our debt-to-capital ratio (being debt/[shareholders' equity + debt]) after these concurrent offerings was 13% as at December 31, 2010 (11% as at December 31, 2009 and 36% as at December 31, 2008) which is well below our targeted maximum gearing level of 50%. During the year ended December 31, 2009, we completed the conversion of the remaining portion of the 8.0% 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 which reduced our debt-to-capital ratio to 11% for the year ended December 2009 from 36% as at December 31, 2008.

Gearing targets are based on a number of factors including operating cash flows, future cash needs for development, capital market conditions, economic conditions, and are assessed regularly.

Our current ratio (being current assets/current liabilities), which measures the ability to meet short term obligations, was 3.18 as at December 31, 2010 (2.22 as at December 31, 2009 and 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, was 2.29 as at December 31, 2010 (1.47 as at December 31, 2009 and 0.98 as at December 31, 2008). These satisfy our target of above 1.50 times and 1.0 respectively.

As at December 31, 2010, our total assets amounted to \$965.5 million, compared with \$631.8 million as at December 31, 2009 and 591.8 million as at December 31, 2008. The increase of \$333.7 million or 52.8% from December 31, 2009 was primarily due to increases in our cash and cash equivalents of \$187.1 million following the concurrent common share and convertible notes offerings conducted during the fourth quarter of 2010, increases in our oil and gas properties of \$82.8 million associated with the appraisal and development of the Elk and Antelope fields and furthering of the CS Project and LNG Project, an increase in inventory balances of \$57.0 million at our refinery due to the timing of shipments, and a net \$8.3 million increase in plant and equipment (after depreciation) mainly due to capitalization of the refinery turnaround, ERP implementation costs and refurbishment of retail sites.

As at December 31, 2010, our total liabilities amounted to \$277.0 million, compared with \$189.8 million as at December 31, 2009 and \$364.7 million as at December 31, 2008. The increase of \$87.2 million or 46% from December 31, 2009 was primarily due to recognition of a \$52.4 million liability relating to the fair value of the debt component of the unsecured 2.75% convertible notes issuance in November 2010, an increase in the working capital facility balance of \$26.6 million and an increase in accounts payable and accrued liabilities of \$16.7 million. This increase in liabilities has been partly offset by a reduction in the IPI liability by \$5.4 million arising from our buy back of certain of those interests, and a \$3.3 million reduction in the secured and unsecured loan balances due to OPIC loan repayments offset by increase in Mitsui's funding of our portion of the CS Project categorized as an unsecured loan. The decrease in liability of \$174.9 million or 48.0% as at December 31, 2009 from December 31, 2008 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.

On August 4, 2010, the JVOA for the proposed CS Project was finalized. The capital cost for the CS Project is currently estimated at \$550.0 million, with approximately \$32.0 million of this to be expended for front end engineering design. Mitsui will be responsible for arranging or providing financing for the capital costs of the plant in the event a positive FID is made.

## ***Analysis of Consolidated Financial Results Comparing Year and Quarter Ended December 31, 2010, 2009 and 2008***

### **Annual Comparative**

Net loss for the year ended December 31, 2010 was \$45.5 million compared with a net profit of \$6.1 million for the same period in 2009, a reduction of \$51.6 million. The operating segments of Corporate, Midstream Refining and Downstream collectively returned a net profit for the year of \$41.4 million, which was the highest level in our operating history. The development segments of Upstream and Midstream Liquefaction yielded a net loss of \$86.9 million for an aggregate net loss of \$45.5 million. The net loss from our development segments was the result of a number of unusual/one time charges. The main items contributing to the consolidated loss for the year were:

- **Loss on extinguishment of IPI liability of \$30.6 million:** During 2010 we bought back 1.45% interest in the IPI agreement for which a total of 754,788 common shares valued at \$50.7 million were issued. We have adopted the extinguishment of liability model for accounting for the buyback of 1.4% of this interest with the difference between fair value and book value of the IPI liability for this interest being expensed, amounting to an \$30.6 million expense for the year. For the remaining 0.05% interest, the investor had already waived their conversion right in 2009. This meant that conveyance accounting was followed and the premium paid to the investor on buyback was capitalized to oil and gas properties. The buyback was a non-cash transaction, the loss on extinguishment did not impact our net cash balance.
- **Settlement of litigation for \$12.0 million – Todd Peters et al v. Phil Mulacek et. al:** In August 2010, we entered into an agreement with the Plaintiffs to settle and release all claims against us and our subsidiaries. Pursuant to the settlement, which was approved by the trial court in September 2010, we issued 199,677 common shares to the Plaintiffs in October 2010, valued at \$12.0 million based on a volume weighted average price calculated over the ten trading days prior to execution of the settlement agreement. The settlement was a non-cash transaction, the expense did not impact our net cash balance.
- **Seismic activity and standby costs expensed for \$17.0 million –** Seismic costs incurred on the programs over the Bwata and Wolverine structures during the year amounted to \$8.7 million. These costs have been expensed as incurred under successful efforts accounting. In addition, during the last quarter of 2010 no drilling activity was conducted while we evaluated the seismic results and drilling equipment underwent maintenance. Our drilling and associated equipment/service crews were on standby during this period. All costs in relation to the maintenance and standby time have been expensed for the year.

Total revenues for the year ended December 31, 2010 were \$807.0 million compared with \$693.1 million and \$919.7 million respectively for the same periods in 2009 and 2008. This increase in the year ended 2010 compared to same period in 2009 was due to the higher crude price environment in the current year and an increase in volume of product sold. The crude price environment in the year ended December 31, 2008 was higher than the years ended December 31, 2010 and 2009. The total volume of all products sold by us was 7.2 million barrels for fiscal year 2010, compared with 6.5 million barrels in 2009 and 6.6 million barrels in 2008.

EBITDA for the year ended December 31, 2010 was negative \$16.5 million, a reduction of \$35.8 million over the \$19.3 million for the same period in 2009, mainly due to the items contributing to the consolidated loss as explained above.

The Upstream segment realized a net loss of \$78.6 million in 2010 (2009 – loss of \$39.5 million, 2008 – profit of \$2.2 million). The increase in the loss in 2010 by \$39.1 million from 2009 was mainly due to a \$16.8 million increase in exploration costs relating mainly to Bwata and Wolverine structures seismic activities and the expensing of crew downtime in the fourth quarter of 2010, \$9.2 million higher intercompany interest charges due to higher loan balances from the parent entity (Corporate segment), and a \$5.2 million reduction in the gain on sale of exploration assets in 2010 compared to 2009 as the prior year included conveyance accounting on the IPI agreement for conversion rights waived by certain IPI investors. During the year 2008, there was no loss relating to the extinguishment of the IPI liability as in 2010 or 2009, the gain on sale of oil and gas properties

were higher compared to 2010 and 2009 mainly due to the sale of our interests in PRL 4 and 5, and also the intercompany interest expense charges were lower than 2010 and 2009 due to lower loan balances.

The Midstream Refining segment generated a net profit of \$32.5 million in 2010 (2009 - \$41.8 million, 2008 - \$4.7 million) mainly on account of better gross margins (an increase of \$13.8 million from 2009) due to higher yielding crude cargos and higher export premiums. This increase in gross margins was offset by the initial recognition in 2009 of \$14.3 million of deferred tax assets in relation to carried forward tax losses and temporary differences, a \$2.6 million increase in derivative losses and a \$3.7 million increase in foreign exchange losses. The net profit in 2009 increased from 2008 mainly on account of hedge accounted and non-hedge accounted derivative gains realized of \$18.2 million, higher yielding crude cargos and higher export premiums, and the recognition of \$14.3 million of deferred tax assets as noted above.

The Midstream Liquefaction segment had a net loss of \$8.4 million (2009 – loss of \$8.4 million, 2008 loss of \$7.9 million) during the 2010 year resulting from higher management expenses and share compensation costs related to the LNG Project development which are not capitalized. As the LNG Project Agreement was signed by the Government of Papua New Guinea with a subsidiary of PNG LNG in December 2009, all direct project related costs since that date have been capitalized to the project rather than expensed.

The Downstream segment generated a net profit of \$6.7 million in 2010 (2009 – profit of \$8.5 million, 2008 – loss of \$1.2 million). The decreased profit was mainly due to a \$3.0 million increase in office and administration expenses from higher staff salary costs, higher recharges from Corporate, higher lease and utility costs resulting from the relocation to new office premises in Papua New Guinea, a \$2.0 million increase in foreign exchange loss and a \$1.7 million increase in income tax expense due to an under-provision of deferred tax expense for 2009 taken during the first quarter of 2010. These decreases have been offset in part by a \$4.6 million improvement in gross margin on the back of increased sales relating to the Exxon Mobil LNG project, the increasing price environment leading to higher margins on inventories sold, and in small part, an upward revision of wholesale prices based on the pricing review completed and published by the ICCC in November 2010. The increase in net profit in 2009 compared to 2008 was mainly on the basis of the positive effect of increasing price environment leading to higher margins on inventories sold as they were written down to its net realizable value as at December 31, 2008.

The Corporate segment generated a net profit of \$3.3 million (2009 – loss of \$4.3 million, 2008 – loss of \$10.6 million) primarily due to an \$8.5 million increase in intercompany interest recharges on loans provided to other segments as a result of higher intercompany loan balances provided to segments, and a \$2.4 million reduction in the interest expense due to the mandatory conversion of all outstanding debentures into common shares during 2009. These increases were partly offset by the \$12.0 million settlement expense to finalize the *Todd Peters v. Phil Mulacek et al* litigation.

### **Quarterly Comparative**

The net loss for the quarter ended December 31, 2010 was \$35.8 million compared with a profit of \$19.3 million for the same quarter of 2009, a reduction of \$55.1 million. This movement was mainly due to a higher loss on extinguishment of IPI liability in the current quarter in relation to a 1.0% IPI interest buyback, an increase in expensed exploration costs on seismic and standby charges as detailed above, and the initial recognition of deferred tax assets in the fourth quarter of 2009 resulting in an income tax benefit in that quarter.

The operating segments of Corporate, Midstream Refining and Downstream collectively derived a net profit for the fourth quarter of \$14.2 million, while the development segments of Upstream and Midstream Liquefaction had a net loss of \$50.0 million, for an aggregate net loss of \$35.8 million.

Total revenues decreased by \$14.9 million from \$209.3 million in the quarter ended December 31, 2009 to \$194.4 million in the quarter ended December 31, 2010.

## Variance Analysis

A complete discussion of each 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, 2010 and 2009.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$51.6)</b>	<b>(\$55.1)</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$14.3	\$10.5	Increase in gross margins mainly due to higher yielding crude cargos and higher export premiums for our refining segment. Downstream margins also increased on increased domestic consumption due to construction activity on the Exxon Mobil LNG project, the increasing price environment leading to higher margins on inventories sold, and in small part due to upward revision of wholesale prices based on the pricing review completed and published by the ICCC in November 2010.
➤	(\$7.8)	(\$3.7)	Higher office and administration and other expenses, mainly resulting from higher salaries and wages expenses due to the strengthening of the AUD against the USD and higher maintenance costs on our rig during the standby in fourth quarter. The increase is also due to higher stock compensation expense and higher consulting costs in relation to the transactions to underpin the development of our Elk Antelope fields, the CS Project and the LNG Project.
➤	(\$16.8)	(\$13.6)	Higher exploration costs during current periods for seismic activity over the Bwata field and the Wolverine prospect which were expensed as incurred, and crew and drilling services stand by charges expensed in the fourth quarter of 2010.
➤	\$1.1	(\$18.6)	Lower loss on extinguishment of IPI liability for the year in relation to the interest buyback of 1.4% interest in 2010, 1.0% of which was purchased in the fourth quarter, compared with 4.3364% interest bought back in 2009. However, the premiums paid on buybacks in 2010 were higher than similar transactions in 2009.
➤	(\$12.0)	\$0.0	Litigation settlement expense on account of the agreed settlement of the <i>Todd Peters v. Phil Mulacek et al</i> litigation for which we issued 199,677 common shares to the Plaintiffs valued at \$12.0 million.
➤	(\$7.5)	(\$3.4)	Foreign exchange movements of PGK against the USD, and lower PGK rates being charged by financial institutions on conversion of the PGK sales revenue into USD for repayment of our crude purchase working capital facility. The rates fluctuate significantly based on the extent to which other PNG participants are looking to convert their foreign currencies. We are unable to undertake PGK currency hedging due to the relatively small size of the PGK foreign exchange market.
➤	\$2.6	(\$1.1)	Lower interest expense for the year primarily due to the mandatory conversion in June 2009 of the remaining portion of the 8% convertible debentures.
➤	(\$5.2)	(\$6.3)	Lower gain on sale of exploration assets due to a \$2.1 million gain on the sale of PPL 244 in the fourth quarter of 2010 compared to a \$7.4 million gain in 2009 due to the waiver by IPI holders of a 6.210% interest of their rights to convert their interest into common shares in the IPI agreement.

- (\$18.5) (\$16.7) Increase in income tax expense during 2010 due to the initial recognition of a \$14.3 million future income tax benefit in December 2009 for Midstream Refining.

### ***Analysis of Consolidated Cash Flows Comparing Year Ended December 31, 2010 and 2009***

As at December 31, 2010, we had cash, cash equivalents and cash restricted of \$280.9 million (December 2009 – \$75.8 million), of which \$47.3 million (December 2009 - \$29.3 million) was restricted. Of the total cash restricted, \$40.7 million (December 2009 - \$22.9 million) was restricted pursuant to the BNP Paribas working capital facility utilization requirements, \$6.3 million (December 2009 – \$6.3 million) was restricted as a cash deposit on the Overseas Petroleum Investment Corporation (“OPIC”) secured loan and the balance was made up of cash deposit on office premises and term deposits on PPL’s.

The cash held as a deposit for the OPIC secured loan relates to our half yearly instalment of \$4.5 million and the related interest that will be payable with the next instalment on June 30, 2011. A waiver previously agreed with OPIC in respect of this deposit requirement expired in June 2009 with the capital raising undertaken at that time.

Our cash outflows from operations for the year ended December 31, 2010 were \$13.6 million compared with inflows of \$44.5 million for the year ended December 31, 2009 (an increase in net cash outflows of \$58.1 million). This reduction in cash flows is mainly due to a \$68.3 million increase in inventories resulting from the timing of crude and export shipments, offset by increases in accounts payable.

Cash outflows for investing activities for the year ended December 31, 2010 were \$111.2 million compared with \$85.6 million for the year ended December 31, 2009. These outflows mainly relate to the net cash expenditure on exploration, appraisal and development activities (net of IPI cash calls) of \$89.4 million, expenditure on plant and equipment of \$22.6 million, and the \$18.0 million movement in the restricted cash balance governed by the BNP Paribas working capital facility and OPIC secured loan. These outflows have been partly offset by the receipt of the final installment of \$13.9 million during first quarter of 2010 relating to the sale of a 2.5% direct working interest in the Elk and Antelope fields to Pacific LNG Operations Ltd. in September 2009, \$1.6 million proceeds from the sale of our interest in PPL 244, and a \$3.2 million increase in accounts payables and accruals of development segments relating to the timing of payments which are classified under investing activities.

Cash inflows from financing activities for the year ended December 31, 2010 amounted to \$311.8 million, compared with a \$38.5 million inflow during 2009. This increase in cash flows includes receipts of cash from the concurrent common shares and convertible notes offerings, the exercise of stock options, receipts of cash contributions from Mitsui and Petromin PNG Holdings Limited (“Petromin”) for Upstream development projects, cash contributions received by PNG LNG for Midstream Liquefaction projects, payments of the OPIC secured loan 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.

## 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, 2010 by business segment, and on a consolidated basis.

Quarters ended (\$ thousands except per share data)	2010				2009			
	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31
Upstream	245	714	1,349	998	1,027	1,011	660	611
Midstream – Refining	158,092	173,379	194,016	152,093	173,438	141,295	114,347	145,523
Midstream – Liquefaction	0	0	0	0	0	1	2	4
Downstream	143,364	133,508	119,300	109,687	118,270	107,712	85,472	78,572
Corporate	15,213	18,295	11,321	12,093	10,539	10,087	8,640	7,753
Consolidation entries	(122,545)	(117,437)	(100,637)	(96,052)	(93,971)	(86,509)	(60,625)	(70,801)
<b>Total revenues</b>	<b>194,369</b>	<b>208,459</b>	<b>225,349</b>	<b>178,819</b>	<b>209,303</b>	<b>173,597</b>	<b>148,496</b>	<b>161,662</b>
Upstream	(41,681)	(11,753)	(3,498)	(1,964)	574	(29,097)	(669)	(469)
Midstream – Refining	13,780	15,785	16,962	4,402	8,492	8,199	14,134	14,747
Midstream – Liquefaction	(1,959)	(4,588)	(3)	(563)	(1,200)	(2,119)	(1,379)	(2,361)
Downstream	4,709	1,674	7,060	4,492	4,391	6,542	4,150	3,241
Corporate	4,566	(4,510)	1,751	4,402	1,765	1,980	1,897	3,051
Consolidation entries	(7,005)	(5,229)	(7,384)	(5,910)	(4,884)	(4,092)	(278)	(7,285)
<b>EBITDA <sup>(1)</sup></b>	<b>(27,590)</b>	<b>(8,621)</b>	<b>14,888</b>	<b>4,859</b>	<b>9,138</b>	<b>(18,587)</b>	<b>17,855</b>	<b>10,924</b>
Upstream	(47,845)	(16,585)	(7,943)	(6,182)	(3,626)	(31,392)	(2,382)	(2,133)
Midstream – Refining	8,531	11,998	12,056	(74)	18,070	3,762	9,624	10,350
Midstream – Liquefaction	(2,114)	(4,970)	(360)	(911)	(1,591)	(2,481)	(1,765)	(2,552)
Downstream	2,642	(325)	3,719	671	2,371	3,440	1,742	964
Corporate	3,381	(5,398)	1,796	3,544	3,036	1,602	(677)	349
Consolidation entries	(403)	908	(1,438)	(191)	1,047	(237)	2,894	(4,332)
<b>Net (loss)/profit</b>	<b>(35,808)</b>	<b>(14,372)</b>	<b>7,830</b>	<b>(3,143)</b>	<b>19,307</b>	<b>(25,306)</b>	<b>9,436</b>	<b>2,646</b>
<b>Net (loss)/profit per share (dollars)</b>								
Per Share – Basic	(0.78)	(0.33)	0.18	(0.07)	0.45	(0.60)	0.25	0.07
Per Share – Diluted	(0.78)	(0.33)	0.17	(0.07)	0.43	(0.60)	0.24	0.07

(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, 2010 for each of our business segments.

### UPSTREAM – YEAR AND QUARTER IN REVIEW

Upstream – Operating results (\$ thousands)	Year ended December 31,	
	2010	2009
Other non-allocated revenue	3,305	3,309
<b>Total revenue</b>	<b>3,305</b>	<b>3,309</b>
Office and administration and other expenses	(13,746)	(7,111)
Exploration costs	(16,982)	(209)
Gain on sale of oil and gas properties	2,141	7,364
Loss on extinguishment of IPI liability	(30,569)	(31,710)
Foreign exchange loss	(3,044)	(1,304)
<b>EBITDA <sup>(1)</sup></b>	<b>(58,895)</b>	<b>(29,661)</b>
Depreciation and amortization	(1,132)	(538)
Interest expense	(18,528)	(9,335)
<b>Loss before income taxes and non-controlling interest</b>	<b>(78,555)</b>	<b>(39,534)</b>
Income tax expense	-	-
<b>Net loss</b>	<b>(78,555)</b>	<b>(39,534)</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 Year and Quarter Ended December 31, 2010 and 2009

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, 2010 and 2009.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$39.0)</b>	<b>(\$44.2)</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	(\$16.8)	(\$13.6)	Higher exploration costs during current period for seismic activity over the Bwata field and the Wolverine prospect, and the preparations for the seismic program over PPL 236 which commenced towards the end of the year. These seismic costs are expensed as incurred under the successful efforts method of accounting. In addition to seismic costs, current period expenses also included the expensing of drilling crew and associated equipment/services standby costs for the fourth quarter of 2010 when no drilling activity was undertaken pending evaluation of the results of our seismic programs completed during the year.
➤	(\$6.6)	(\$2.2)	Increase in office and administration and other expenses mainly due to higher drilling rig maintenance expenses during the standby period in the fourth quarter of 2010, and higher consulting costs in relation to the transactions that are intended to underpin the development of our Elk Antelope condensate stripping and LNG facilities.
➤	\$1.1	(\$18.6)	Lower loss on extinguishment of IPI liability for the year in relation to the interest buyback of a 1.4% interest in 2010, 1.0% of which occurred in the fourth quarter, compared with 4.3364% interest bought back in 2009. However, the premiums paid on buybacks in 2010 were higher than similar

- transactions in 2009.
- (\$5.2) (\$6.3) Lower gain on sale of exploration assets due to \$2.1 million gain on sale of PPL 244 in 2010 compared to \$7.4 million gain in 2009 due to the waiver of common share conversion rights by holders of a 6.210% IPI interest.
  - (\$9.2) (\$1.4) Higher interest expense due to an increase in inter-company loan balances provided to fund exploration and development activities during the year.
  - (\$1.7) (\$0.7) Increase in foreign exchange loss due to the increased Papua New Guinea denominated expenses in our operations requiring conversion of higher USD amounts into PGK. PGK has fluctuated significantly against the USD during the year.

## MIDSTREAM - REFINING – YEAR AND QUARTER IN REVIEW

Midstream Refining – Operating results (\$ thousands)	Year ended December 31,	
	2010	2009
External sales	298,071	299,673
Inter-segment revenue	379,344	274,736
Interest and other revenue	166	194
<b>Total segment revenue</b>	<b>677,581</b>	<b>574,603</b>
Cost of sales and operating expenses	(605,603)	(516,349)
Office and administration and other expenses	(11,939)	(9,901)
Derivative (loss)/gain	(1,592)	1,009
Foreign exchange loss	(7,518)	(3,790)
<b>EBITDA <sup>(1)</sup></b>	<b>50,929</b>	<b>45,572</b>
Depreciation and amortization	(10,355)	(10,932)
Interest expense	(6,585)	(7,150)
<b>Profit before income taxes and non-controlling interest</b>	<b>33,989</b>	<b>27,490</b>
Income tax (expense)/benefit	(1,478)	14,316
Non-controlling interest	-	-
<b>Net profit</b>	<b>32,511</b>	<b>41,806</b>
<b>Gross Margin <sup>(2)</sup></b>	<b>71,812</b>	<b>58,060</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,	
	2010	2009	2010	2009
Throughput (barrels per day) <sup>(1)</sup>	21,550	20,966	24,682	21,155
Capacity utilization (based on 36,500 barrels per day operating capacity)	34%	44%	53%	47%
Cost of production per barrel <sup>(2)</sup>	\$4.35	\$2.92	\$3.78	\$3.18
Working capital financing cost per barrel of production <sup>(2)</sup>	\$0.58	\$0.49	\$0.47	\$0.40
Distillates as percentage of production	58.70%	61.00%	51.00%	58.63%

(1) Throughput per day has been calculated excluding shut down days. During 2010 and 2009, the refinery was shut down for 81 days and 80 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 finished product that we imported during the year.

During the fourth quarter of 2010, the refinery was shut down from October 1, 2010 to November 2, 2010 to perform turnaround maintenance, which is required every five years. Inventories of finished products were built up during the period prior to the shutdown to meet the domestic demand during the shutdown period.

### Analysis of Midstream - Refining Financial Results Comparing the Year and Quarter Ended December 31, 2010 and 2009

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, 2010 and 2009.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$9.3)</b>	<b>(\$9.5)</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$13.8	\$11.0	Change in gross margin was due to the following contributing factors: <ul style="list-style-type: none"> <li>+ Steady increase in crude prices with comparatively lower volatility.</li> <li>+ Improved LSWR and naphtha crack spreads and premiums over those from 2009.</li> <li>- Hedge gains realized on close out of long term hedges in early 2009, compared with no hedge accounted contracts in the current period.</li> <li>- Refinery shutdown for month of October for turnaround maintenance program.</li> </ul>
➤	(\$2.0)	(\$1.3)	Increase in office and administration costs was driven by an increase in staff salary expenses, mainly due to higher stock compensation expenses and a one-off catch-up payment of airfares tax since 2007 for refinery employees. This payment was made after rejection of our application made to the Internal Revenue Commission in Papua New Guinea for exemption from this tax.
➤	(\$3.7)	(\$3.3)	Increase in foreign exchange loss due to movements of PGK against the USD, and PGK rates being charged by financial institutions on conversion of the PGK sales revenue into USD for repayment of

working capital facility. The exchange rates fluctuate significantly based on the extent to which other PNG participants are looking to convert their foreign currencies. We are unable to do any currency hedging due to the relatively small size of the PGK foreign exchange market.

- (\$2.6) (\$1.1) Movement in gains/(losses) from derivative contracts undertaken as part of our risk management strategy that were not accounted for as hedge accounted contracts.
- \$0.6 \$0.5 Reduction in interest expense due to capital repayments of the OPIC loan, and lower intercompany loan balances on higher profits being generated by the refinery operations.
- (\$15.8) (\$15.4) Increase in income tax expense for the current year and quarter were driven by the initial recognition of a \$14.3 million future income tax benefit in December 2009 relating to carried forward tax losses and temporary differences, compared with a \$1.5 million future income tax expense during 2010 which was mainly the movement in temporary differences associated with depreciation of property, plant and equipment.

## MIDSTREAM - LIQUEFACTION – YEAR AND QUARTER IN REVIEW

Midstream Liquefaction – Operating results (\$ thousands)	Year ended December 31,	
	2010	2009
Interest and other revenue	1	8
<b>Total segment revenue</b>	<b>1</b>	<b>8</b>
Office and administration and other expenses	(7,023)	(7,108)
Foreign exchange (loss)/gain	(90)	41
<b>EBITDA <sup>(1)</sup></b>	<b>(7,112)</b>	<b>(7,059)</b>
Depreciation and amortization	(25)	(57)
Interest expense	(1,253)	(1,218)
<b>Loss before income taxes and non-controlling interest</b>	<b>(8,390)</b>	<b>(8,334)</b>
Income tax benefit/(expense)	36	(55)
<b>Net loss</b>	<b>(8,354)</b>	<b>(8,389)</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 Year and Quarters Ended December 31, 2010 and 2009***

This segment results include the proportionate consolidation of our interest in the joint venture development of a proposed midstream gas liquefaction facilities. The development is being progressed in joint venture with Pacific LNG Operations Ltd ("Pac LNG") through PNG LNG Inc. We currently have an economic interest of 86.66% in this joint venture entity and its subsidiaries.

All costs incurred, subsequent to the execution of the shareholders' agreement on July 31, 2007, and through the pre-acquisition and feasibility stage were expensed as incurred, unless they were directly identified with the property, plant and equipment of the LNG Project. Since the execution of the LNG Project Agreement by a

subsidiary of PNG LNG with the State of Papua New Guinea in December 2009, all project-related direct costs have been capitalized, other than overheads and other costs that are incurred in the normal course of running the business, which are expensed.

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, 2010 and 2009.

	<b>Yearly Variance</b> (\$ millions)	<b>Quarterly Variance</b> (\$ millions)	
	<b>\$0.0</b>	<b>(\$0.5)</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$0.1	(\$0.7)	Reduction in office, administration and other expenses for the year due to capitalization of direct expenses relating to the LNG Project since executing the LNG Project Agreement in December 2009. The prior period balances also included loss on the proportionate consolidation of PNG LNG subsequent to the acquisition of Merrill Lynch's interest in that company in early 2009. These decreased expenses were offset by higher management expenses and share compensation costs related to the LNG Project development which are not capitalized.

## DOWNSTREAM YEAR AND QUARTER IN REVIEW

Downstream – Operating results (\$ thousands)	Year ended December 31,	
	2010	2009
External sales	504,304	388,806
Inter-segment revenue	483	185
Interest and other revenue	1,072	1,035
<b>Total segment revenue</b>	<b>505,859</b>	<b>390,026</b>
Cost of sales and operating expenses	(470,772)	(359,623)
Office and administration and other expenses	(15,976)	(12,911)
Foreign exchange (loss)/gain	(1,176)	832
<b>EBITDA <sup>(1)</sup></b>	<b>17,935</b>	<b>18,324</b>
Depreciation and amortization	(2,787)	(2,650)
Interest expense	(3,739)	(4,130)
<b>Profit before income taxes and non-controlling interest</b>	<b>11,409</b>	<b>11,544</b>
Income tax expense	(4,701)	(3,027)
<b>Net profit</b>	<b>6,708</b>	<b>8,517</b>
<b>Gross Margin <sup>(2)</sup></b>	<b>34,015</b>	<b>29,368</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,	
	2010	2009	2010	2009
Sales volumes (millions of liters)	170.2	159.1	626.5	588.8

### **Analysis of Downstream Financial Results Comparing the Year and Quarters Ended December 31, 2010 and 2009**

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, 2010 and 2009.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$1.8)</b>	<b>\$0.3</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	\$4.6	\$2.5	Increase in gross margin mainly driven by a 6.4% increase in volumes compared to prior year on the back of increased sales relating to the Exxon Mobil LNG project, the increasing price environment leading to higher margins on inventories sold, and in small part, an revision of wholesale prices based on the pricing review completed and published by the ICCC in November 2010.
➤	(\$1.7)	(\$0.1)	Increase in income tax expense due to under-provision of deferred tax expense in the prior year.
➤	(\$3.1)	(\$2.1)	Increase in office and administration and other expenses mainly relating to higher staff salary costs, higher recharges from Corporate, and higher lease and utility costs on relocation to new office premises in Papua New Guinea.
➤	(\$2.0)	(\$0.2)	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)	Year ended December 31,	
	2010	2009
Inter-segment revenue	32,564	21,194
Interest revenue	24,335	15,825
Other non-allocated revenue	23	-
<b>Total revenue</b>	<b>56,922</b>	<b>37,019</b>
Office and administration and other expenses	(40,291)	(29,241)
Derivative gain	527	-
Foreign exchange gain	1,051	915
Litigation settlement expense	(12,000)	-
<b>EBITDA <sup>(1)</sup></b>	<b>6,209</b>	<b>8,693</b>
Depreciation and amortization	(106)	(275)
Interest expense	(1,541)	(3,952)
<b>Profit before income taxes and non-controlling interest</b>	<b>4,562</b>	<b>4,466</b>
Income tax expense	(1,240)	(158)
<b>Net profit</b>	<b>3,322</b>	<b>4,308</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, 2010 and 2009***

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, 2010 and 2009.

<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
<b>(\$1.0)</b>	<b>\$0.3</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤ (\$12.0)	\$0.0	Litigation settlement expense on account of the agreed settlement of the <i>Todd Peters v. Phil Mulacek et al</i> litigation for which we issued 199,677 common shares to the plaintiffs valued at \$12.0 million.
➤ \$11.0	(\$0.4)	Reduced interest expenses (net of recharged intercompany interest revenue from other segments) due to conversion in June 2009 of the remaining portion of the 8.0% debentures issued in May 2008, and higher interest charges to other business segments on increased loan balances.
➤ \$0.3	\$1.0	Decrease in net office and administration and other expenses for the year after recharges to other streams (included in inter-segment revenue). Higher office and administration and other expenses, mainly resulting from higher salaries and wages expenses due to a strengthening of the AUD against the USD compared with the prior periods.

## CONSOLIDATION ADJUSTMENTS – YEAR AND QUARTER IN REVIEW

Consolidation adjustments – Operating results (\$ thousands)	Year ended December 31,	
	2010	2009
Inter-segment revenue <sup>(1)</sup>	(412,392)	(296,115)
Interest revenue <sup>(5)</sup>	(24,281)	(15,792)
<b>Total revenue</b>	<b>(436,673)</b>	<b>(311,907)</b>
Cost of sales and operating expenses <sup>(1)</sup>	374,818	273,989
Office and administration and other expenses <sup>(2)</sup>	36,325	21,379
<b>EBITDA <sup>(3)</sup></b>	<b>(25,530)</b>	<b>(16,539)</b>
Depreciation and amortization <sup>(4)</sup>	130	130
Interest expense <sup>(5)</sup>	24,282	15,792
<b>Loss before income taxes and non-controlling interest</b>	<b>(1,118)</b>	<b>(617)</b>
Non-controlling interest	(7)	(8)
<b>Net loss</b>	<b>(1,125)</b>	<b>(625)</b>
<b>Gross Margin <sup>(6)</sup></b>	<b>(37,574)</b>	<b>(22,126)</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, 2010 and 2009**

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, 2010 and 2009.

	<b>Yearly Variance (\$ millions)</b>	<b>Quarterly Variance (\$ millions)</b>	
	<b>(\$0.5)</b>	<b>(\$1.5)</b>	<b>Net profit/(loss) variance for the comparative periods primarily due to:</b>
➤	(\$0.5)	(\$1.5)	Decrease in net income due to changes in 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.

## 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, 2010.

Organization	Facility	Balance outstanding December 31,	Effective interest rate	Maturity date
OPIC secured loan	\$44,500,000	\$44,500,000	6.80%	December 2015
BNP Paribas working capital facility	\$190,000,000 <sup>(2)</sup>	\$50,023,559 <sup>(1)</sup>	2.69%	Subsequent to year end, this was renewed until January 31, 2012
Westpac PGK working capital facility	\$30,280,000	\$1,230,767	9.50%	October 2011
BSP PGK working capital facility	\$18,925,000	\$0	9.20%	October 2011
2.75% convertible notes	\$70,000,000	\$70,000,000	7.91% <sup>(4)</sup>	November 2015
Mitsui unsecured loan <sup>(3)</sup>	\$5,456,757	\$5,456,757	6.26%	See detail below

(1) Excludes letters of credit totaling \$93.7 million, which reduce the available balance of the facility to \$46.3 million at December 31, 2010.

(2) Subsequent to the year end, the facility has been increased by \$30.0 million for a total facility of \$220.0 million.

(3) Facility is to fund our share of the CS Project costs as they are incurred pursuant to the JVOA.

(4) Effective rate after bifurcating the equity and debt components of the convertible note offering.

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

On June 12, 2001, InterOil entered into a loan agreement with OPIC for provision of an \$85.0 million project financing facility for the development of our refinery in PNG. The balance as at December 31, 2010 was \$44.5 million. The loan is primarily secured by the assets of the refinery and by a parent guarantee from InterOil Corporation, with certain secondary sponsorship security also in place. The interest rate on the loan is equal to the agreed U.S. Government treasury cost applicable to each promissory note that was issued and is 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. At December 31, 2010, \$6.3 million is being held on deposit to secure our June 30, 2011 principal and interest payments on the secured loan.

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

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 has a limit of \$130.0 million and finances the purchases of hydrocarbons via the issuance of documentary letters of credit and standby letters of credit, short term advances, advances on merchandise, freight loans, and has a sublimit of Euro 18.0 million or the USD equivalent for hedging transactions via BNP Paribas Commodity Indexed Transaction Group or other acceptable counter parties. Facility 2 allows borrowings of up 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 in order to reduce Facility 1 balances. 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 total facility is renewable annually, and subsequent to year end, the facility was renewed until January 31, 2012 with an increase in Facility 1 limit by an additional \$30.0 million to \$160.0 million, and a maximum availability of \$220.0 million for the combined facility.

As of December 31, 2010, \$46.3 million remained available for use under the facility. The facility bears interest at LIBOR plus 3.5% on short term advances. The weighted average interest rate under the working capital facility was 2.69% for year ended December 31, 2010 (compared to 2.13% for the same period of 2009), after including the reduction in interest due to the deposit amounts (restricted cash) maintained as security.

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

On October 24, 2008, we secured a PGK 150.0 million (approximately \$56.8 million) combined revolving working capital facility for our Downstream wholesale and retail petroleum products distribution business from Bank of South Pacific Limited and Westpac Bank PNG Limited. The facility limit as at December 31, 2010 was PGK 130.0 million (approximately \$49.2 million).

The Westpac facility limit is PGK 80.0 million (approximately \$30.3 million) and the BSP facility limit was initially PGK 70.0 million (approximately \$26.5 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 2010 at a limit of PGK 50.0 million (approximately \$18.9 million). As at December 31, 2010, PGK 3.3 million (approximately \$1.2 million) of this combined facility had been utilized. The weighted average interest rate under the Westpac facility was 9.50% for the year to December 31, 2010 while the weighted average interest rate under the BSP facility was 9.20%.

#### ***2.75% Convertible Notes (Corporate)***

On November 10, 2010, we completed the issue of \$70.0 million unsecured 2.75% convertible notes with a maturity of five years. The note holders have the right to convert their note into common shares at any time at a conversion rate of 10.4575 common shares per \$1,000 principal amount of notes (which results in an effective initial conversion price of approximately \$95.625 per share). We have the right to redeem the notes if the daily closing sale price of the common shares has been at least 125% of the conversion price then in effect for at least 15 trading days during any 20 consecutive trading day periods. Accrued interest on these notes is to be paid semi-annually in arrears, in May and November of each year, commencing May 2011.

#### ***Mitsui Unsecured Loan (Upstream)***

On April 15, 2010, we entered into a preliminary works joint venture and preliminary works financing agreement with Mitsui relating to the CS Project. On August 4, 2010, the JVOA for the condensate stripping facilities was entered into. Mitsui and InterOil are to hold equal shares in the joint venture. Mitsui will be responsible for arranging or providing financing for the capital costs of the plant.

The portion of funding that relates to Mitsui's share of the CS Project as at December, 2010, amounting to approximately \$6.4 million, is held in current liabilities as the agreement requires repayment if a positive FID is not reached. The portion of funding that relates to our share of the CS Project (amounting to \$5.5 million), funded by Mitsui, is classed as an unsecured loan and interest is accrued daily based on LIBOR plus a margin of 6%.

While cash flows from operations are expected to be sufficient to cover our operating commitments, should there be a major long term deterioration in refining or wholesale and retail margins, our operations may not generate sufficient cash flows to cover all of the interest and principal payments under our debt facilities noted above. Also, our exploration and development activities require funding beyond our operational cash flows and the cash balances we currently hold. 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

Currently our share of expenditures on exploration wells, appraisal wells and extended well programs are funded from contributions made by IPI investors, capital raising activities, operational cash flows and asset sales.

On October 30, 2008, Petromin, a government entity mandated to invest in resource projects on behalf of the State, entered into an agreement to take a 20.5% direct interest in the Elk and Antelope fields once the State's right to such an interest crystallized under relevant legislation. 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 PDL, which has not yet occurred. The agreement contains certain provisions applicable in the event that the PDL is not applied for or issued within certain timeframes. 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 expected to occur, and we are obliged to distribute the proceeds received from Petromin between the existing interest holders (currently InterOil, IPI holders and Pac LNG) 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, 2010, \$15.4 million has been received from Petromin.

Cash calls are made to IPI investors, Pac LNG (for its 2.5% direct interest acquired during 2009) and Petromin for their share of amounts spent on appraisal wells and extended well programs pursuant to the relevant agreements in place with them.

In addition to the loan provided by Mitsui, as noted under summary of debt facilities section above, as at December 31, 2010, \$6.5 million has been received from Mitsui for their proportion of cash calls and sunk costs in relation to the CS Project.

On November 2, 2010, the Company filed a base shelf prospectus for a total of \$300.0 million securities with the Alberta Securities Commission, the Ontario Securities Commission, the British Columbia Securities Commission, and a corresponding registration statement on Form F-10 with the United States Securities and Exchange Commission (the "SEC") pursuant to the multi-jurisdictional filing system. On November 5, 2010, we undertook concurrent public offerings of \$70.0 million aggregate principal amount of 2.75% convertible senior notes due 2015 and 2,800,000 common shares at \$75.00 per share, raising gross proceeds of \$280.0 million from the combined offerings. The net proceeds after deducting the underwriting discounts, commissions and offering expenses were \$266.0 million. The concurrent offerings closed on November 10, 2010.

## Summary of Cash Flows

(\$ thousands)	Year ended December 31,		
	2010	2009	2008
<b>Net cash inflows/(outflows) from:</b>			
Operations	(13,561)	44,500	15,586
Investing	(111,158)	(85,567)	(47,390)
Financing	311,846	38,546	36,913
<b>Net cash movement</b>	<b>187,127</b>	<b>(2,521)</b>	<b>5,109</b>
Opening cash	46,450	48,971	43,862
<b>Closing cash</b>	<b>233,577</b>	<b>46,450</b>	<b>48,971</b>

### ***Analysis of Cash Flows Provided By/(Used In) Operating Activities Comparing the Years Ended December 31, 2010 and 2009***

The following table outlines the key variances in the cash flows from operating activities between years ended December 31, 2010 and 2009:

**Yearly  
variance  
(\$ millions)**

**(\$58.1)**

**Variance for the comparative periods primarily due to:**

- (\$15.1) Increase in cash used by operations prior to changes in operating working capital mainly due to the timing difference between the recognition and settlement of long term hedges that were settled in early 2009.
- (\$43.0) Increase in cash used by operations due primarily to a \$68.3 million increase in inventories due to timing of crude and export shipments, offset by an increase in accounts payable.

**Analysis of Cash Flows Provided By/(Used In) Investing Activities Comparing the Years Ended December 31, 2010 and 2009**

The following table outlines the key variances in the cash flows from investing activities between years ended December 31, 2010 and 2009:

**Yearly  
variance  
(\$ millions)**

**(\$25.6)**

**Variance for the comparative periods primarily due to:**

- (\$21.3) Higher cash outflows for the year to December 31, 2010 on exploration expenditures compared to the prior year. The outflows related primarily to the Antelope 2 horizontal drilling, the development seismic program on the Antelope structure, seismic on the Bwata field and the Wolverine prospect, and progressing the CS Project.
- \$8.3 Higher cash calls and related inflows from IPI investors.
- (\$10.8) Higher expenditure on acquisition of plant and equipment. 2010 expenditure was mainly associated with capitalized LNG Project costs, ERP implementation, refurbishment of retail sites, tank upgrades and additional camp facilities at the refinery.
- \$15.5 Receipt in 2010 of the final installment of \$13.9 million relating to the sale of 2.5% direct working interest in the Elk and Antelope fields to Pac LNG in September 2009 and \$1.6 million proceeds from the sale of our interest in PPL 244.
- (\$14.9) Higher cash outflows due to movement in our secured cash restricted balances in line with the usage of the BNP working capital facility.
- (\$2.4) Increase 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 and Midstream Liquefaction operations.

**Analysis of Cash Flows Provided By/(Used In) Financing Activities Comparing the Years Ended December 31, 2010 and 2009**

Following table outlines the key variances in the cash flows from financing activities between years ended December 31, 2010 and 2009:

**Yearly  
variance  
(\$ millions)**

<b>\$273.3</b>	<b>Variance for the comparative periods primarily due to:</b>
➤ \$129.4	Higher net proceeds from the issuance of 2,800,000 common shares in November 2010.
➤ \$70.8	Higher utilization of the BNP Paribas working capital facility consistent with the higher inventory holding balances at year end.
➤ \$66.3	Net proceeds after transaction costs from the issuance of \$70.0 million of 2.75% convertible notes in November 2010.
➤ \$11.9	Funding from Mitsui relating to the CS Project.
➤ \$0.9	Net proceeds from the cash call made to Pac LNG for its share of costs incurred by PNG LNG and its subsidiaries during 2010.
➤ (\$3.6)	Proceeds received from Pac LNG during the year ending December 30, 2009 relating to the acquisition of a direct 2.5% working interest in the Elk and Antelope fields.
➤ (\$1.4)	Proceeds received from Petromin for contributions towards cash calls made with respect to development activities for the Elk and Antelope fields.
➤ (\$1.0)	Net transaction costs relating to \$25.0 million secured Clarion Finanz loan for which funds were received in August and repaid in November 2010.

## Capital Expenditures

### Upstream Capital Expenditures

Gross capital expenditures for exploration in Papua New Guinea for the year ended December 31, 2010 were \$113.1 million compared with \$91.8 million during 2009.

The following table outlines the key expenditures in the year ended December 31, 2010:

<b>Yearly (\$ millions)</b>	<b>Expenditures in the year ended December 31, 2010 due to:</b>
<b>\$113.1</b>	
➤ \$61.2	Drilling, testing and completion costs on the Antelope-2 well.
➤ \$4.5	Conducting a development seismic program on the Antelope structure.
➤ \$8.7	Conducting seismic activity in relation to the Bwata field and the Wolverine prospect.
➤ \$116.6	Costs for early works in respect of the CS Project.
➤ \$2.3	Site preparation costs for the Antelope-3 appraisal well.
➤ \$6.7	Drilling crew and services stand by costs during fourth quarter of 2010.
➤ \$13.1	Other expenditures, including purchase of a second rig and other fixed assets, and drilling consumable purchases.

IPI investors and Pac LNG (2.5% direct interest in Elk and Antelope fields) are required to fund 24.3886% as at December 31, 2010 of the Elk and Antelope extended well program costs to maintain their interest in that those fields. The amounts capitalized in our books, or expensed as incurred, in relation to the extended well program are the net amounts after adjusting for these interests.

Petromin has agreed to fund 20.5% of ongoing costs for developing the fields. Petromin contributed \$5.0 million in the year ended December 31, 2010 bringing the total advance payment received to \$15.435 million. All funds received are being treated as a deposit until a PDL is granted.

The preliminary funding agreement entered into with Mitsui provides for funding by Mitsui of all the costs relating to the CS Project. 50% of the funding is for Mitsui's share of the CS Project and the other 50% is funding by Mitsui of our share of the CS Project. Mitsui has contributed \$11.9 million during the year ended December 31, 2010 for both Mitsui's and our share of the project. In the event that a positive FID is not reached or made, we will be required to refund all of Mitsui's contributions (i.e. for our share and Mitsui's) within a specified period.

#### *Midstream Capital Expenditures*

Capital expenditures totaled \$7.0 million in our Midstream Refining segment for the year ended December 31, 2010, mainly associated with the major turnaround shutdown, tank upgrades and camp and office refurbishments.

Following the signing of the LNG Project Agreement with the State in December 2009, \$1.9 million of costs incurred during the year in relation to the Midstream - Liquefaction segment have been capitalized.

#### *Downstream Capital Expenditures*

Capital expenditures for the Downstream segment totaled \$7.6 million for the year ended December 31, 2010. These expenditures mainly related to office refurbishments and a number of upgrade projects across various terminals and depots.

#### *Corporate Capital Expenditures*

Capital expenditures for the Corporate segment totaled \$3.7 million for the year ended December 31, 2010. These expenditures mainly related to project costs in relation to the ERP implementation.

All expenditures associated with the public offerings in November 2010 have been capitalized in the balance sheet to the respective equity and debt balances recognized in relation to the offerings.

### **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.

The majority of our "net cash from operating activities" adjusted for "proceeds from/(repayments of) working capital facilities" are used in our appraisal and development programs for the Elk and Antelope fields in PNG. Our net cash from working activities is not sufficient to fund those appraisal and development programs.

#### *Upstream*

We are required under our \$125.0 million IPI Agreement of 2005 to drill eight exploration wells. We have drilled four wells to date. As at December 31, 2010, we are committed to spend a further \$83.0 million as a condition of renewal of our petroleum prospecting licenses up to 2014. Of this \$83.0 million commitment, as at December 31, 2010, management estimates that satisfying this license commitment would also satisfy our commitments to the IPI investors in relation to drilling the final four wells and satisfy the commitments in relation to the IPI agreement.

In addition, the terms of grant of PRL 15, requires us to spend a further \$73.0 million on the development of the Elk and Antelope fields by the end of 2014.

We will likely 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.

We will also be required to obtain substantial amounts of financing for the development of the Elk and Antelope fields, condensate stripping facilities, LNG Project and delivery of gas to the LNG facilities, and it would take a number of years to complete these projects. In the event that the commercial viability of these projects is established, we plan to use a combination of debt, equity and/or 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.

### *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 2011. 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 long term 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*

On September 28, 2010, we and Liquid Niugini Gas Ltd. (a wholly owned subsidiary of PNG LNG) signed a heads of agreement with EWC to construct a three million tonne per annum land based LNG facility in the Gulf Province of Papua New Guinea. Following this agreement, and subsequent to year end, on February 2, 2011, the parties signed certain conditional agreements defining certain parameters for the aforementioned development, construction, financing and the operation of the planned land-based modular LNG facilities. These facilities are intended to be developed in phases.

The LNG facilities are intended to be developed in two phases, 2 mtpa followed by a 1 mtpa expansion. In return for its commitment to fully fund the construction of the LNG facilities, the agreed terms provide that EWC is to be entitled to a fee of 14.5% of the proceeds from LNG revenue, less agreed deductions, and subject to adjustments based on timing and execution.

Completion of any LNG project will require substantial amounts of financing and construction will take a number of years to complete. As a joint venture partner in the Elk Antelope and LNG Project, if the project is completed, we would be required to fund our share of certain common facilities of the development. No assurances can be given that we will be able to source sufficient gas, successfully construct such a facilities, or as to the timing of such construction. The availability and cost of capital is highly dependent on market conditions and our circumstances 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 2011.

## Contractual Obligations and Commitments

The following table contains information on payments required to meet contracted obligations due for each of the next five years and thereafter. It should be read in conjunction with our financial statements for the year ended December 31, 2010 and the notes thereto:

Contractual obligations (\$ thousands)	Payments Due by Period						
	Total	Less than 1 year	1 - 2 years	2 - 3 years	3 - 4 years	4 - 5 years	More than 5 years
Secured and Unsecured loans <sup>(3)</sup>	49,957	14,457	9,000	9,000	9,000	8,500	-
Convertible notes obligations	70,000	-	-	-	-	70,000	-
Indirect participation interest <sup>(1)</sup>	1,384	540	844	-	-	-	-
Petroleum prospecting and retention licenses <sup>(2)</sup>	156,000	31,000	31,000	34,900	24,750	34,350	-
<b>Total</b>	<b>277,341</b>	<b>45,997</b>	<b>40,844</b>	<b>43,900</b>	<b>33,750</b>	<b>112,850</b>	<b>-</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 21 to our financial statements for the year ended December 31, 2010.

(2) The amount pertaining to the petroleum prospecting and retention licenses represents the amount we have committed as a condition of renewal of our petroleum prospecting licenses up to 2014. Of this \$83.0 million commitment, as at December 31, 2010, management estimates that satisfying this license commitment would also satisfy our commitments to the IPI investors in relation to drilling the final four wells and satisfy the commitments in relation to the IPI agreement. In addition, the terms of grant of PRL15, requires us to spend a further \$73.0 million on the development of the Elk and Antelope fields by the end of 2014.

(3) This excludes the contractual interest payments on the principal amount. The effective interest rate on this loan for the year ended December 31, 2010 was 6.80%. 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, 2010, 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, 2010 (December 2009 - \$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.

Breckland Limited, a company controlled by Mr. Roger Grundy, one of our directors, provides technical and advisory services to us on normal commercial terms. Amounts paid or payable to Breckland for technical services during the year ended December 31, 2010 amounted to \$21,923 (December 2009 - \$nil).

## 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 (none of which are outstanding). As of December 31, 2010, we had 47,800,552 common shares (50,690,516 common shares on a fully diluted basis) and no preferred shares outstanding. The potential dilutive instruments outstanding as at December 31, 2010 included employee stock options and restricted stock in respect of 1,812,459 common shares, IPI conversion rights to 340,480 common shares, 732,025 common shares relating to the convertible notes issuance during 2010 and 5,000 common shares able to be issued to Petroleum Independent and Exploration Corporation in exchange for the 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 instruments which we generally use are the over-the-counter (“OTC”) swaps. 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. 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. By 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, 2010, we had a net payable of \$178,578 (December 2009 – nil) relating to commodity hedge contracts for which hedge accounting was not applied.

No gain was recognized from the effective portion of priced out hedge accounted contracts for the year ended December 31, 2010 (December 2009 – \$17.2 million gain), and no gain was recognized on the ineffective portion of hedge accounted contracts for the year ended December 31, 2010 (December 2009 – gain of \$0.3 million). A loss of \$1.6 million was recognized on the non-hedge accounted derivative contracts for the year ended December 31, 2010 (December 2009 – gain of \$0.7 million).

In addition to the commodity derivative contracts, we have also entered into foreign exchange derivative contracts to manage our foreign exchange risk in relation to Australian Dollars (“AUD”). As at December 31, 2010 we had no receivables relating to our foreign currency derivatives. A gain of \$0.5 million was recognized on foreign exchange derivative contracts for the year ended December 31, 2010.

For a detailed description of our current derivative contracts as of December 31, 2010, see Note 8 to our consolidated financial statements for the year ended December 31, 2010.

## 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 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 fuel) 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 Mean of Platts Singapore (“MOPS”) which is the benchmark price for refined products in the region in which we operate.

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 November 2010, the Papua New Guinea Independent Consumer and Competition Commission (“ICCC”) completed a review of the pricing arrangements for petroleum products in PNG. The purpose of the review was 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. The report recommended an increase in margins for wholesaling and certain other activities while the retail margin is to remain the same. It also recommended some increases in monitoring industry activity in PNG. The revised pricing and monitoring regime will next be reviewed at the end of 2014.

## Financing Arrangements

We continue to monitor liquidity risk by setting of acceptable gearing levels and ensuring its monitored. Our aim is to maintain our debt-to-capital ratio, or gearing levels, (debt/(shareholders’ equity + debt)) at 50% or less. This was achieved throughout 2010. Gearing levels were 13% in December 2010 and 11% in December 2009. Our gearing levels as at December 31, 2010 were slightly affected by the public equity and debt offerings completed in November 2010 as described below.

On November 10, 2010, we completed concurrent public offerings of \$70.0 million aggregate principal amount of 2.75% convertible senior notes due 2015 and 2,800,000 common shares at a price of \$75.00 per share for \$210.0 million, raising gross proceeds of \$280.0 million from the combined offerings.

For details of other financial arrangements in place, see “Liquidity and Capital Resources – Summary of Debt Facilities”.

We had cash, cash equivalents and cash restricted of \$280.9 million as at December 31, 2010, of which \$47.3 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 \$46.3 million of the combined BNP working capital facility available for use in our Midstream – Refining operations, and \$48.0 million of the Westpac/BSP combined working capital facility available for use in our Downstream operations.

## Crude Prices

Crude prices increased steadily throughout 2010 as compared to 2009, with the price of Tapis crude oil (as quoted by the Asian Petroleum Price Index (“APPI”)) starting the year at \$81 per bbl closing at a two year high of \$97 per bbl. Tapis was the benchmark for setting crude prices within the region where we operate however toward the end of 2010 most crude suppliers in the region that we utilise when purchasing crude feedstock for our refinery have switched to a pricing basis using Dated Brent. Dated Brent pricing mirrored the Tapis trend and increased from \$79 per bbl to finish the year at \$93 per bbl. The average price for Dated Brent for 2010 was \$81 per bbl compared to \$61 per bbl for Dated Brent for 2009.

We had, as at year end, \$46.3 million of the combined BNP working capital facility available for use in our Midstream – Refining operations, and approximately \$48.0 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.

Any volatility of crude prices means that we face significant timing and margin risk on our crude cargos. A significant portion of this timing and margin risk is managed by us through short and long term hedges. The

number of hedges in place declined in both 2010 and 2009 with a reduction in the volatility in prices. There were no outstanding hedge accounted derivative contracts as at December 31, 2010. There was a net payable of \$178,578 as at December 31, 2010 relating to outstanding non-hedge accounted contracts which were still not priced out as at December 31, 2010.

## 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.

The volatility of Singapore Tapis hydroskimming margins decreased during 2010, and margins are generally improved in comparison with the previous year.

Distillate margins to APPI Tapis strengthened slightly in 2010 compared with historical levels due to increasing demand and suppressed Tapis crude pricing. Naphtha crack spreads were positive for most of 2010 which has positively affected our gross margin for the period.

## Domestic Demand

Sales results for our refinery for 2010 indicate that Papua New Guinea's domestic demand for middle distillates (which includes diesel and jet fuels) from the refinery has increased by approximately 6.9% as compared with 2009. The total volume of all products sold by us was 7.2 million barrels for fiscal year 2010 compared with 6.5 million barrels in 2009. Total volume of domestic sales only for 2010 was 4.3 million barrels as compared with 4.0 million barrels in 2009.

The refinery on average sold 11,780 bbls per day of refined petroleum products to the domestic market during fiscal year 2010 compared with 10,933 bbls per day in 2009.

## 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 stayed constant at between 0.2% and 0.3% for 2010. 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 five months ended May 31, 2010 (from 0.37 to 0.353). However, it has since strengthened against the USD during the seven months ended December 31, 2010 (from 0.353 to 0.3785).

## 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 "Forward Looking Statements" above. Detailed risk factors can be found under the heading "*Risk Factors*" in our 2010 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 effect of changes in estimates on future periods have not been disclosed in these consolidated financial statements as estimating it is impracticable. 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, 2010, 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, 2010 and 2009 were \$14.1 million and \$16.9 million, respectively.

During the year ended December 31, 2009, we recognized a \$14.3 million future income tax benefit relating to carried forward tax losses and temporary differences associated with Midstream – Refining segment as management considered it more likely than not that the deferred tax assets will be realized.

### *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 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 as current legislation does not require it. 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, 2010**

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 our financial statements.

### **Changeover to International Financial Reporting Standards (“IFRS”)**

The AcSB has adopted IFRS as issued by IASB as Canadian GAAP, effective January 1, 2011. In anticipation of the change, the AcSB had revised 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. This change is part of a global shift to provide consistency in financial reporting in the global marketplace.

The SEC currently allows foreign private issuers using IFRS as issued by the IASB 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 in relation to our systems and internal controls. Discussions with our external auditors have been ongoing and will continue throughout the implementation phases.

We will continue to monitor any revisions being made by AcSB to the Canadian accounting standards to conform to IFRS in advance of the 2011 reporting periods. 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.

We have completed the review and evaluation of IFRS 1 – ‘First-time adoption of International Financial Reporting Standards’. Noted below are the main elections/or availed exemptions InterOil on transition, that are available to first time adopters of IFRS.

- **Business Combinations:** A first-time adopter may elect not to apply IFRS 3 - ‘Business Combinations’ (as revised in 2008) retrospectively to past business combinations (business combinations that occurred before the date of transition to IFRSs). However, if a first-time adopter restates any business combination to comply with IFRS 3 (as revised in 2008), it shall restate all later business combinations and shall also apply IAS 27 (as amended in 2008) from that same date. We have made the election not to apply IFRS 3 retrospectively to past business combinations.
- **Property, Plant and Equipment:** An entity may elect to measure an item of property, plant and equipment at the date of transition to IFRSs at its fair value and use that fair value as its deemed cost at that date. We have made the election not to revalue our property, plant and equipment to fair value or deemed cost. Historical cost will be maintained as plant and equipment cost base on transition.
- **Foreign currency translation reserve:** consistent with the our Canadian GAAP treatment, IAS 21 requires an entity: (a) to recognize some translation differences in other comprehensive income and accumulate these in a separate component of equity; and (b) on disposal of a foreign operation, to reclassify the cumulative translation difference for that foreign operation (including, if applicable, gains and losses on related hedges) from equity to profit or loss as part of the gain or loss on disposal. An election can be made to be exempted from this requirement on transition and start with ‘zero’ translation differences. We have not made the election to start with ‘zero’ its cumulative translation differences balance, and have elected to continue with the current translation differences in Comprehensive income as these are already in compliance with IAS 21. As we are maintaining the Foreign Currency Translation Reserve, deferred tax on the balance will also have to be recognized by crediting opening equity balances as under IFRS the translation reserve should be disclosed net of taxes. There will be no profit and loss impact due to the deferred tax recognition.
- **Oil and Gas assets:** 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. Para D1 of IFRS 1 provides an exemption in relation to Oil and Gas assets by allowing Companies to continue using the same policies as used under the previous GAAP and carrying forward the carrying amounts of the Oil and Gas assets under Canadian GAAP into IFRS. We have availed this exemption and elected to maintain our Oil and Gas assets at carrying amount under Canadian GAAP, which will be the deemed cost under IFRS.
- **Interests in Joint Ventures:** CICA Section 3055 differs from IAS 31 as IAS 31 permits the use of either the proportionate consolidation method or the equity method to account for joint ventures. IAS 31 recommends the use of proportionate consolidation as it better reflects the substance and economic reality, however, it does permit the use of equity method. CICA Section 3055 only allows the use of proportionate consolidation method to account for joint ventures. We have elected to maintain our joint venture accounting under the proportionate consolidation model for both our incorporated and unincorporated joint venture interests.

## Impact of adoption of IFRS on financial reporting

Based on our evaluation to date and existing IFRS, the only expected adjustment required to our balance sheet as at January 1, 2010 is the recognition of the deferred tax on foreign currency translation reserve as noted above. In addition to this, there would be changes to the presentation to our consolidated financial statements and related note disclosures.

## 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,		
	2010	2009	2008
Midstream – Refining	677,415	574,409	786,114
Downstream	504,787	388,991	556,868
Corporate	32,564	21,194	24,567
Consolidation Entries	(412,392)	(296,115)	(451,970)
<b>Sales and operating revenues</b>	<b>802,374</b>	<b>688,479</b>	<b>915,579</b>
Midstream – Refining	(605,603)	(516,349)	(779,832)
Downstream	(470,772)	(359,623)	(536,920)
Corporate <sup>(1)</sup>	-	-	-
Consolidation Entries	374,818	273,989	428,129
<b>Cost of sales and operating expenses</b>	<b>(701,557)</b>	<b>(601,983)</b>	<b>(888,623)</b>
Midstream – Refining	71,812	58,060	6,282
Downstream	34,015	29,368	19,948
Corporate <sup>(1)</sup>	32,564	21,194	24,567
Consolidation Entries	(37,574)	(22,126)	(23,841)
<b>Gross Margin</b>	<b>100,817</b>	<b>86,496</b>	<b>26,956</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)	2010				2009			
	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31
Upstream	(41,681)	(11,753)	(3,498)	(1,964)	574	(29,097)	(669)	(469)
Midstream – Refining	13,780	15,785	16,962	4,402	8,492	8,199	14,134	14,747
Midstream – Liquefaction	(1,959)	(4,588)	(3)	(563)	(1,200)	(2,119)	(1,379)	(2,361)
Downstream	4,709	1,674	7,060	4,492	4,391	6,542	4,150	3,241
Corporate	4,566	(4,510)	1,751	4,402	1,765	1,980	1,897	3,051
Consolidation Entries	(7,005)	(5,229)	(7,384)	(5,910)	(4,884)	(4,092)	(278)	(7,285)
<b>Earnings before interest, taxes, depreciation and amortization</b>	<b>(27,590)</b>	<b>(8,621)</b>	<b>14,888</b>	<b>4,859</b>	<b>9,138</b>	<b>(18,587)</b>	<b>17,855</b>	<b>10,924</b>
<b>Subtract:</b>								
Upstream	(5,481)	(4,600)	(4,367)	(4,080)	(4,056)	(2,164)	(1,563)	(1,552)
Midstream – Refining	(1,509)	(1,693)	(1,651)	(1,731)	(1,973)	(1,682)	(1,709)	(1,786)
Midstream – Liquefaction	(184)	(376)	(351)	(342)	(379)	(348)	(333)	(158)
Downstream	(835)	(938)	(1,167)	(800)	(930)	(1,045)	(1,013)	(1,142)
Corporate	(1,158)	(342)	(20)	(20)	(27)	-	(1,600)	(2,325)
Consolidation Entries	6,571	6,107	5,916	5,687	5,905	3,823	3,141	2,923
<b>Interest expense</b>	<b>(2,596)</b>	<b>(1,842)</b>	<b>(1,640)</b>	<b>(1,286)</b>	<b>(1,460)</b>	<b>(1,416)</b>	<b>(3,077)</b>	<b>(4,040)</b>
Upstream	-	-	-	-	-	-	-	-
Midstream – Refining	(1,040)	101	(366)	(173)	14,316	-	-	-
Midstream – Liquefaction	36	-	-	-	(8)	(3)	(32)	(12)
Downstream	(495)	(322)	(1,524)	(2,361)	(411)	(1,398)	(733)	(485)
Corporate	(11)	(529)	97	(797)	1,340	(339)	(800)	(359)
Consolidation Entries	(2)	(2)	(2)	-	(3)	(1)	(2)	(2)
<b>Income taxes and non-controlling interest</b>	<b>(1,512)</b>	<b>(752)</b>	<b>(1,795)</b>	<b>(3,331)</b>	<b>15,234</b>	<b>(1,741)</b>	<b>(1,567)</b>	<b>(858)</b>
Upstream	(683)	(232)	(78)	(138)	(144)	(132)	(150)	(112)
Midstream – Refining	(2,700)	(2,195)	(2,888)	(2,572)	(2,765)	(2,755)	(2,801)	(2,611)
Midstream – Liquefaction	(7)	(6)	(6)	(6)	(7)	(10)	(20)	(20)
Downstream	(737)	(739)	(651)	(660)	(679)	(658)	(662)	(651)
Corporate	(16)	(17)	(32)	(41)	(43)	(40)	(174)	(18)
Consolidation Entries	33	32	32	32	33	33	32	32
<b>Depreciation and amortisation</b>	<b>(4,110)</b>	<b>(3,157)</b>	<b>(3,623)</b>	<b>(3,385)</b>	<b>(3,605)</b>	<b>(3,562)</b>	<b>(3,775)</b>	<b>(3,380)</b>
Upstream	(47,845)	(16,585)	(7,943)	(6,182)	(3,626)	(31,392)	(2,382)	(2,134)
Midstream – Refining	8,531	11,998	12,056	(74)	18,071	3,762	9,624	10,349
Midstream – Liquefaction	(2,114)	(4,970)	(360)	(911)	(1,593)	(2,481)	(1,764)	(2,551)
Downstream	2,642	(325)	3,718	671	2,371	3,440	1,742	964
Corporate	3,381	(5,398)	1,796	3,544	3,034	1,601	(677)	350
Consolidation Entries	(403)	908	(1,437)	(191)	1,050	(236)	2,893	(4,332)
<b>Net (loss)/profit per segment</b>	<b>(35,808)</b>	<b>(14,372)</b>	<b>7,830</b>	<b>(3,143)</b>	<b>19,307</b>	<b>(25,306)</b>	<b>9,436</b>	<b>2,646</b>

## **PUBLIC SECURITIES FILINGS**

---

You may access additional information about us, including our Annual Information Form for the year ended December 31, 2010, 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 AND INTERNAL CONTROLS OVER FINANCIAL REPORTING**

---

The Company's certifying officers have designed disclosure controls and procedures, as such term is defined in National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings ("National Instrument 52-109"), or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed the Company in its interim filings is processed, summarized and reported within the time periods specified in applicable Canadian securities legislation.

The Company's certifying officers are responsible for establishing and maintaining internal control over financing reporting ("ICFR"), as such term is defined in National Instrument 52-109. The control framework the Company's officers used to design the Company's ICFR is the framework established by the Committee of Sponsoring Organizations (COSO) entitled – Internals Controls – Integrated Framework.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its ICFR as at December 31, 2010 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2010, the Company's ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The Company has implemented a new ERP System in line with its growth objective. The ERP System implementation required installation of new hardware and software into our Information Technology environment and the way we record, process and report financial transactions. Effective June 1, 2010 we migrated to the new ERP System for companies in our Corporate, Midstream and Upstream segments, with a plan to migrate the operating company of our Downstream segment during the first half of 2011.

Management has reviewed the internal controls over financial reporting affected by the implementation of the ERP System and made appropriate changes to internal controls as part of the implementation. Following the implementation, these new controls were evaluated and tested according to the Company's established processes. Based on this evaluation, the Company believes that it has designed adequate and appropriate internal control over financial reporting to ensure that the financial statements were materially accurate for the year ended December, 31 2010.

During the year ended December 31, 2010, there has been no other change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to affect, the Company's internal control over financial reporting, other than as noted above.

## **GLOSSARY OF TERMS**

---

**AUD** Australian dollars.

**Barrel, Bbl** Unit volume measurement used for petroleum and its products.

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

**BSP** Bank of South Pacific Ltd.

**CGR** Condensate to gas ratio.

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

**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 sulfur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

**CSP Joint Venture or CSP JV** The Joint Venture Operating Agreement (“JVOA”) entered into for the proposed condensate stripping facilities with Mitsui or the joint venture formed to develop and operate the proposed condensate stripping facilities as the context requires.

**CS Project** The proposed condensate stripping facilities, including gathering and condensate pipeline, condensate storage and associated facilities being progressed in joint venture with Mitsui.

**DST** A drill stem test and is a procedure for isolating and testing the surrounding geological formation through the drill pipe.

**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 a non-GAAP measure used to analyze operating performance. See “*Non-GAAP Measures and Reconciliation*”.

**Elk Antelope Project** The Elk Antelope wells, and the common jetty and loading facilities.

**ERP** Enterprise Resource Planning System.

**EWC** Energy World Corporation Limited., a company organized under the laws of Australia.

**FEED** Front end engineering and design.

**Feedstock** Raw material used in a refinery or other processing plant.

**FID** Final investment decision. Such a decision is ordinarily the point at which a decision is made to proceed with a project and it becomes unconditional.

**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 sulfur or other non-hydrocarbon compounds.

**ICCC** Independent Consumer and Competition Commission in Papua New Guinea.

**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 2010 Annual Information Form.

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

**Joint Venture Company or PNG LNG** PNG LNG, Inc., a joint venture company established in 2007 to construct the proposed liquefaction facilities. Shareholders are InterOil LNG Holdings Inc., a wholly-owned subsidiary of InterOil, and Pac LNG.

**JVOA** Joint Venture Operating Agreement.

**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 for transportation purposes, and then returned to a gaseous state to be used as fuel. 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.

**LNGL** Liquid Niugini Gas Limited, a wholly owned subsidiary of PNG LNG formed in Papua New Guinea.

**LNG Project** The development by us of liquefaction facilities in Papua New Guinea described as our Midstream Liquefaction business segment and being undertaken as a joint venture with Pac LNG through the Joint Venture Company, presently being pursued with EWC, inter alios, in accordance with certain conditional agreements signed in February 2011.

**LSWR** Low Sulphur Waxy Residue.

**Mitsui** Mitsui & Co., Ltd., a company organized under the laws of Japan and/or certain of its wholly-owned subsidiaries (as the context requires).

**Naphtha** That portion of the distillate obtained from the refinement of petroleum which is an intermediate between the lighter gasoline and the heavier benzene. It is a feedstock destined either for the petrochemical industry or for gasoline production by reforming or isomerisation within a refinery.

**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.

**OPIC** Overseas Private Investment Corporation, an agency of the United States Government.

**Pac LNG** Pacific LNG Operations Ltd., a company incorporated in the Bahamas and affiliated with Clarion Finanz A.G. This company is our joint venture partner in the LNG Project (holding equal voting shares in PNG LNG), holds a 2.5% direct interest in the Elk and Antelope fields and is an IPI holder.

**Petromin** Petromin PNG Holdings Limited, a company incorporated in PNG by the State.

**PDL** Petroleum Development License. The right granted by the State to develop a field for commercial production.

**PGK** the Kina, the 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 State 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.

**Westpac** Westpac Bank PNG Limited.