MAGELLAN PETROLEUM CORP /DE/
Form 10-K/A
September 28, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K/A
(Amendment No. 1)
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2012, or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
for the transition period from to
Commission file number 1-5507
Magellan Petroleum Corporation
(Exact name of registrant as specified in its charter)

Delaware	06-0842255
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1950, Denver, CO	80203
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (720) 484-2400
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of each exchange on which registered
Common stock, par value $0.01 per share	NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer o	Smaller reporting company þ
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No þ

The aggregate market value of the common equity held by non-affiliates of the registrant, based on the $0.968 closing price per share of the registrant's common stock as reported by the NASDAQ Capital Market, as of December 30, 2011 (the last business day of the most recently completed second fiscal quarter) was $41,241,284. For the purpose of this calculation, shares of common stock held by each director and executive officer and by each person who owns ten percent or more of the outstanding shares of common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for any other purpose.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:

Common stock, par value $0.01 per share, 53,885,594 shares outstanding as of September 17, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement related to the Annual Meeting of Stockholders for the fiscal year ended June 30, 2012, are incorporated by reference in Part III of this Form 10-K to the extent stated herein.

EXPLANATORY NOTE

This Amendment No. 1 to the Annual Report on Form 10-K (the "Amended 10-K") of Magellan Petroleum Corporation ("Magellan" or "our") amends our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, that was filed with the U.S. Securities and Exchange Commission (the "SEC") on September 24, 2012 (the "Original 10-K"). This Amended 10-K does not reflect a change in our consolidated results of operations, consolidated financial position, or consolidated cash flows as reported in the Original 10-K. This Amended 10-K is filed solely (i) to furnish the XBRL files with the "detailed tagging" data required to be included with this report, within the applicable grace period for furnishing such files; (ii) to correct a typographical error in the date of Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm and to change the description of the retrospective adjustments and the related financial statement footnote references to make them consistent throughout such report; and (iii) to correct the Foreign transaction (gain) loss amount appearing on page 20 under the Non-GAAP Financial Measures and Reconciliation section and on page 41 under the General and Administrative Expense section of Management's Discussion and Analysis of Financial Condition and Results of Operations, and to make a corresponding correction to the affected Adjusted EBITDAX amount for the fiscal year ended June 30, 2012, disclosed on pages 5, 20, and 32. No other changes were made to the Original 10-K.

This Amended 10-K does not reflect other events occurring after the filing of the Original 10-K, including exhibits, or modify or update those disclosures which may be affected by subsequent events. This Amended 10-K should be read in conjunction with Magellan's filings made with the SEC subsequent to the filing of the Original 10-K, as those filings may have been amended, as information in such reports and documents may update or supersede certain information contained in this Amended 10-K. Accordingly, this Amended 10-K only amends the items listed in the above paragraph, and no other information in the Original 10-K is amended hereby.

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PART 1

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Magellan Petroleum Corporation (the "Company" or "Magellan" or "we" or "us") is an independent energy company engaged in the exploration, development, production, and sale of crude oil and natural gas. The Company conducts its operations through two wholly owned subsidiaries: Nautilus Poplar LLC ("NP"), which owns Poplar, a highly attractive oil field in the Williston Basin; and Magellan Petroleum Australia Limited ("MPAL"), a successful independent oil and gas company in existence since 1964 active in Australia and the United Kingdom.

Magellan was founded in 1957 and incorporated in Delaware in 1967. The Company's common stock has been trading on the NASDAQ since 1972, and trades under the ticker symbol "MPET."

Our principal offices are located at 1775 Sherman Street, Suite 1950, Denver, Colorado, 80203, and our telephone number is (720) 484-2400.

STRATEGY

Our strategy is to enhance shareholder value by maximizing the value of our existing assets. Our portfolio of operations includes several early stage oil and gas exploration and development projects, the successful development of which requires significant capital, as well as engineering, and management resources. We are committed to investing in these projects to establish their technical and economic viability. In turn, we will determine the most efficient way to create value and returns for our shareholders.

SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2012

Fiscal year 2012 was a year of significant transition for Magellan. We made numerous changes to the structure and operations of our business that we believe have favorably impacted our future ability to generate value for our shareholders. During the year, we have strengthened our balance sheet with a significant cash position, gained full control and operatorship of our core assets, stabilized our operational and administrative platform, and initiated a number of cost saving measures. All of these actions will allow us to fund and execute our strategy to prove the value of our existing assets in an efficient manner.

Financial Performance

During the fiscal year, financial results were significantly negatively impacted by the planned termination of key revenue streams in Australia, namely the Palm Valley long term gas contract and the Amadeus Gas Trust. To address this sharp decline in performance, we have focused our efforts on replacing revenues and addressing our cost base. However, the effect of these initiatives has only marginally impacted the results of fiscal year 2012.

Revenues. For the fiscal year ended June 30, 2012, revenues totaled $13.7 million compared to $18.2 million in the prior year, a decrease of 25%. This decrease was primarily the result of the termination at Palm Valley of the 25-year gas sales contract with Northern Territory Power and Water Corporation ("PWC") (with the 25 year gas sales contract with PWC sometimes hereinafter referred to as the "PWC Contract") during January 2012, the termination of the Amadeus Gas Trust revenue stream during fiscal year 2011, and the sale of Magellan's interests in the Mereenie oil and gas field in May 2012. The termination of both the Amadeus Gas Trust revenue and the PWC Contract had been planned since 1983 and 2006, respectively.

During fiscal year 2012, our share of production at Poplar increased due to a combination of our workover program and the consolidation of our ownership in the leases of Poplar. Moreover, we have entered into a new gas sales contract at Palm Valley, which will ramp up to replace by 2015 the volumes previously sold under the PWC Contract at improved prices.

Net income and EPS. For the fiscal year ended June 30, 2012, net income totaled $26.5 million ($0.49/basic share), compared to a net loss of $32.4 million ($(0.62)/basic share) in the prior year. The increase in net income is primarily the result of closing the Santos SA transaction whereby Magellan sold its interests in Mereenie to Santos and Santos sold its interests in the Palm Valley and Dingo fields to the Company, resulting in a gain on sale of assets of $36.2 million and the tax effect of recording the Company's Australian Petroleum Resource Rent Tax ("PRRT") which was enacted during the fiscal year 2012 and effective from July 1, 2012.

Adjusted EBITDAX. For the fiscal year ended June 30, 2012, Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) totaled negative $11.2 million, compared to negative

$4.8 million in the prior year, a change of 135%. This decrease was the result of decreased revenues and increased lease operating expenses, offset by savings of $1.7 million in general and administrative expenses (excluding stock based compensation and foreign transaction loss).

Cash. As of June 30, 2012, Magellan had $41.2 million in cash and cash equivalents as compared to $20.4 million at the end of the prior fiscal year. The increase of $20.8 million was primarily driven by the completion of the Santos SA (see Santos asset swap transaction below), which generated $26.6 million in net cash proceeds for the Company. Our cash balance allows us to pursue our strategy of deploying capital resources towards assessing the potential value of our existing assets and determining the most efficient way to enhance shareholder value.

Rationalization of Asset Portfolio

During the fiscal year, Magellan executed a series of corporate transactions aimed at streamlining our corporate structure and gaining control and operatorship of our core assets.

Consolidation of ownership in Poplar. In the United States, we restructured and fully consolidated our ownership in Poplar (defined below) in September 2011, increasing the Company's economic exposure to the potential upside value of this asset while simplifying processes and procedures relating to accounting, reporting, and capital funding.

Santos asset swap transaction. On May 25, 2012, Magellan Petroleum (N.T.) Pty Ltd ("MPNT"), a wholly owned subsidiary of MPAL, and Santos QNT Pty Ltd and Santos Limited (collectively the "Santos Entities") completed a Sale Agreement (the "Santos SA"), and became the sole owner of the Palm Valley Interests and of the Dingo Interests, while Santos became the sole owner of the Mereenie Interests (see Note 2). As a result, we can now pursue a niche strategy of marketing Amadeus Basin gas to the mining industry in central Australia while reducing both field operating and overhead costs.

Initiation of Strategy to Prove-Up the Value of our Assets

During this past fiscal year, management articulated a strategy to focus on proving up the value of the Company's existing assets as the most economic way of increasing shareholder value. Towards that end, management has begun a number of initiatives to evaluate and determine the potential of the Company's oil and gas properties.

CO_2-EOR at Poplar. In the shallower formations at Poplar, which Magellan 100% owns and operates, management believes that the Charles formation is a potential candidate for a CO_2-enhanced oil recovery project ("CO_2-EOR"). Over the past year, we laid the groundwork for a CO_2-EOR pilot. After completing a detailed 3-D reservoir model earlier in the fiscal year, we commissioned laboratory analyses of oil samples from the Charles formation, the results of which confirm the potential viability of CO_2-EOR in that formation at Poplar. In addition, we have used the EPU 119 well to conduct CO_2 injectivity tests at reservoir conditions, the results of which tests were also favorable.

Other shallow formations of Poplar. Geological and geophysical analyses have led management to believe that there are other shallow formations at Poplar besides the Charles formation that contain significant hydrocarbon resources. In January 2012, Magellan identified a new pool discovery in the Amsden formation with the completion of the EPU 117 well, which has since produced commercial quantities of oil. Management is currently evaluating whether it is more economical to re-complete existing wells at Poplar in the Amsden formation or to drill new wells.

VAALCO farmout. In the United States, we farmed out the deeper intervals at Poplar to VAALCO Energy (USA), Inc. ("VAALCO") in September 2011. Under this arrangement, VAALCO will earn a 65% working interest in those intervals upon completion of three test wells aimed at evaluating the production potential of certain deep formations, in particular the Bakken/Three Forks formation. Magellan is carried 100% for the drilling and completion costs of these three wells and will be entitled to 35% of the gross revenue from the well less its proportionate share of lease burdens and taxes.

Improvements to Operating Assets

Poplar shallow intervals. Much of Poplar's current production is conventional production from the Charles formation generated by wells drilled in the 1950s and 1970s. These wells require significant workovers and maintenance to maintain stable production. Magellan implemented a workover program during the past fiscal year to assess the effectiveness of certain production-enhancing technologies, including stimoil treatments, acid stimulations, and water shut-off treatments. These assessments are ongoing, and have contributed to the increase in lease operating expenses during fiscal year 2012. If they are successful, these production enhancing technologies will be deployed on a broader scale and are expected to improve the production and profitability of the existing wells at Poplar.

Palm Valley. On May 25, 2012, MPNT and the Santos Entities completed the Santos SA, and MPNT became the sole owner of the Palm Valley Interests and of the Dingo Interests, while Santos became the sole owner of the Mereenie Interests, see Note 2. In the Amadeus basin in Australia, in connection with the Santos SA, Magellan executed a long-term sales agreement with Santos to sell substantially all of the remaining gas reserves from Palm Valley. Under this agreement, Magellan now sells gas from Palm Valley to Santos, who on-sells the gas to third party customers. As of June 30, 2012, there were two customers receiving gas from Palm Valley. Sales volumes from Palm Valley are expected to increase to approximately 1.5 Bcf per year by fiscal 2015 and are expected to be sold at prices significantly higher than those realized under the former long-term contract with PWC. Magellan also began to implement operational efficiencies at Palm Valley that have allowed for the reduction of field staff from ten to five workers while maintaining good oil and gas field practice.

Implementation of Recurring Cost Savings

During this fiscal year, Magellan reduced its general and administrative expenses (excluding stock based compensation and foreign transaction loss) by $1.7 million, or 12% . This reduction in expenses was primarily due to a $3.0 million reduction in third party consulting expenses, which resulted from reduced transaction expenses and the recruitment of additional staff that allowed us to internalize functions previously outsourced. This investment in human resources will leave the Company better prepared to handle the development of our projects in compliance with applicable laws and regulations. In addition, we have undertaken a number of cost saving initiatives, the positive impact of which in fiscal year 2012 was partially offset by implementation costs. These initiatives will have a greater impact in fiscal year 2013. Among our efforts to reduce costs, we consolidated our Portland, Maine, and Denver, Colorado, offices into a new single headquarters in Denver, Colorado, and we have streamlined our investor relations processes. Through fiscal year 2013, we will continue to implement cost savings initiatives to bring our cost structure more in line with our peers.

Overhaul of Financial and Administrative Functions

Over the past twelve months, management addressed a number of deficiencies and inefficiencies in the financial and administrative functions of the Company. With these issues now resolved, management believes we are better prepared for, and can be fully focused on, implementing our operational plans.

Remediation of material weakness. When the Company published its fiscal year 2011 Form 10-K, management concluded that the Company did not maintain effective internal controls over financial reporting, in particular in the area of the consolidated statement of cash flows and the review of third party expert work for significant, complex, and/or non-routine accounting issues. Management took this finding extremely seriously, and took significant measures to remediate these weaknesses. Management believes that remediating these weaknesses has now been accomplished.

Over the past year, we have also overhauled our accounting systems by bolstering our accounting staff, initiated the implementation of new accounting and land software, improving internal control processes, and reshaping the way we present our consolidated financial statements, to be more in line with industry practice. These efforts are essential to effectively running a business and establishing investor trust in our accounts.

Investor relations. In recent months, we have renewed our investor relations efforts to help the market better understand the intrinsic value of, and to attract a larger institutional following to, our stock. We have changed how we report our consolidated financial statements to be more in line with industry practice, launched a new website with detailed information about our assets, and created a new investor presentation which lays out our projects and milestones.

Relocation of headquarters. Recently we completed the relocation of the Company's headquarters from Portland, Maine, to Denver, Colorado. Consolidating our offices will achieve operational and organizational efficiencies. Basing our Company in an oil and gas hub will allow us to access talented professionals and service providers experienced in oil and gas and increase our exposure to new oil and gas opportunities. Management expects this move will prove critical to our success in growing this business.

OUTLOOK FOR FISCAL YEAR 2013

During fiscal year 2013, Magellan intends to execute on its strategy of proving the potential of its existing assets. We are particularly focused on the four projects below, which we intend to fund through a combination of the Company's cash resources and the risk capital invested by our farmout and joint venture partners.

- Implementing a pilot CO_2-EOR project at Poplar;
- Shooting and processing 3-D seismic over NT/P82, our exploration block offshore Australia; and
- Determining an exploration program for the unconventional formations in our United Kingdom leases.

- Evaluating the potential of, and possibly participating in the development of, the deeper formations at Poplar with our partner, VAALCO;

Management believes that each of these projects has significant potential that, if realized, will change the reserves and underlying value of our stock. Specific steps and milestones for each of these key areas are discussed below. By pursuing these courses of action, management expects that, by the end of fiscal year 2013, the Company will be able to validate and articulate clearly the value potential of its assets and will be able to determine the most appropriate course of action with respect to each asset to achieve the best value for its shareholders.

Pilot CO_2-EOR Project

In fiscal year 2013, the Company intends to evaluate the potential of CO_2-EOR in the Charles formation at Poplar by drilling a pilot CO_2-EOR, which consists of five-wells, including one CO_2 injector well and four producing wells. Magellan expects to incur up to $10.0 million in capital costs on these wells. Timing of the drilling of these wells will depend on the permitting process and drilling rig availability. The four producing wells are designed to yield both conventional oil production from the Charles formation and enhanced production as a result of the CO_2-EOR. As such, these four wells will constitute a portion of the wells to be drilled in the projections of our proved undeveloped reserves.

Poplar Deeper Formations

Under the terms of our agreement with VAALCO, VAALCO is required to spud and complete three test wells in the deeper formations at Poplar by December 31, 2012. The second test well, EPU 133-H, was completed as a horizontal well in the Bakken/Three Forks formation in September 2012. VAALCO has announced its intention to drill and complete the third test well as another horizontal well in the Bakken/Three Forks formation. The first test well, the EPU 120, was a vertical well drilled to a depth of 9,251 feet to test certain formations below the Bakken/Three Forks. Following VAALCO's determination that this well had not encountered hydrocarbons in commercial quantities, VAALCO announced its intention to recomplete this well as another horizontal Bakken/Three Forks well in fiscal year 2013. As a result of these three wells, we expect that by the end of fiscal year 2013 we will better understand the value potential of our approximately 22,000 net acres at Poplar.

Despite VAALCO's determination regarding the EPU 120 with respect to formations deeper than the Bakken/Three Forks, the Company believes the log data and core samples taken during the drilling phase of this well yielded encouraging results for the Nisku, Red River, and Winnipeg formations that justify further exploration of these formations in the future.

NT/P82, Offshore Australia

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in the NT/P82 Exploration Permit. Magellan acquired this permit in May 2010, when it was engaged in pursuing the Evans Shoal transaction. 2-D seismic previously shot over the block shows a potential "bright spot" suggestive of a large gas resource estimated within a range of one to three Tcf. In accordance with the terms of the permit, which is due to expire in May 2016, the Company is planning to shoot 3-D seismic over the permit area, subject to environmental and permitting approvals, at a cost of less than $5.0 million, including the costs of processing and analyzing the seismic. The processing and analysis is expected to be complete by the end of fiscal year 2013, after which Magellan will have a much better understanding of the nature and size of the potential hydrocarbon resources in the permit area. If the results of the 3-D seismic are favorable, Magellan will then seek to design and implement an exploration and development plan for the block, most likely with a partner experienced in offshore drilling.

United Kingdom Exploration Plan

In fiscal year 2013, the Company intends to determine a definite course of action for exploring the unconventional formations underlying its licenses, most of which are due to expire by June 2015. Our primary focus in the United Kingdom is on establishing the potential value of the unconventional play underlying the licenses we co-own with Celtique Energie. Following our completion in fiscal year 2012 of 2-D seismic shot over these licenses, we have now fulfilled all our requirements except the drilling of a well. One potential strategy involves attracting an appropriate farmout partner to drill the wells required by these licenses.

With regard to the three licenses Magellan owns 100%, one of these is due to expire in September 2012 and is unlikely to be renewed, thereby reducing our gross and net acres in the United Kingdom to 361,762 and 192,622, respectively. Following the exploration work conducted with Celtique, management does not consider this license to be core to our strategy due to its location and assessed potential.

With respect to the Markwells Wood-1 well, operated by Northern Petroleum, following a long-term production test during fiscal year 2012, the well has been suspended and is currently being assessed by Northern for further actions.

OPERATIONS

Magellan operates in the single industry segment of oil and gas exploration and production. We have two reportable geographic segments, NP and MPAL, corresponding to our operations in the United States, and in Australia and the United Kingdom, respectively. NP's oil and gas assets consist of its interests in Poplar in the Williston Basin. MPAL's oil and gas assets consist of interests in the Palm Valley, Dingo, and Mereenie (prior to May 25, 2012) fields in the Amadeus Basin, onshore Australia; NT/P82, an exploration block in the Bonaparte Basin, offshore Australia; and various exploration licenses in the Weald and Wessex Basins, onshore United Kingdom. The locations of the Company's key oil and gas properties are presented

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in the map below. For certain additional information about the Company's reportable segments, see Note 9 to the financial statements included in Item 8: Financial Statements and Supplementary Data of this report.

Magellan's Areas of Operations

United States - Poplar

In the United States, Magellan owns Poplar, an oil field located in Roosevelt County, Montana. Our acreage position covers substantially all of Poplar Dome, the largest geologic structure in the western Williston Basin, the "layer cake" structure of which provides multiple formations with hydrocarbon resource potential.

The field was discovered in the 1950s by Murphy Oil, who actively explored and developed the Charles formation for two decades. By the time Magellan acquired Poplar in 2009, technological advances in oil and gas exploration allowed us to reevaluate Poplar's known formations and to discover new ones.

Poplar is composed of a 100% working interest in the oil and gas leases within the East Poplar Unit ("EPU") in Roosevelt County, Montana, and the working interests in various oil and gas leases that are adjacent to or near EPU ("Northwest Poplar" or "NWP") with the working interests varying between 63% and 100% in such leases (the Company's combined working interests in EPU and NWP are herein referred to as “Poplar”).

Our interests at Poplar include a 100% operated working interest in the interval from the surface to the top of the Bakken/Three Forks formation and a 35% non-operated working interest below that interval, which includes the Bakken/Three Forks formations.

Magellan 100% operated intervals. Magellan's current objectives are to prove up the potential of Poplar's various formations and to establish the viability of a CO_2-EOR project in the Charles formation, in which the substantial volume of oil in place offers Magellan a chance to significantly increase its oil reserves.

VAALCO 65% operated intervals. In September 2011, we farmed out part of our interest in the Bakken/Three Forks and deeper formations to VAALCO in return for their commitment to drill three exploration wells. This arrangement allows us to focus on the shallower formations while VAALCO tests the deeper formations, including the Bakken/Three Forks, Nisku, and Red River, on our collective behalf.

Australia - Amadeus Basin

In the Amadeus Basin, located near Alice Springs in central Australia, Magellan wholly owns 100% of the working interests in and operates two gas fields, Palm Valley and Dingo.

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Palm Valley. Palm Valley was discovered in 1965 and has been reliably selling natural gas since 1983. As of June 2012, the field has produced a cumulative total of 158 Bcf of gas. Through its direct connection to the Amadeus-Darwin Gas Pipeline, Palm Valley is able to meet the needs of its potential customers in Darwin, Northern Territory, and the mining operations adjacent to this pipeline. In 2012, Magellan entered into a new long-term gas sales contract with Santos whereby the Company has the ability to sell up to approximately 23 Bcf of natural gas, representing the majority of what the Company believes are the field's remaining gas reserves, over the next 17 years. To date Santos has future sale commitments for 11.5 Bcf of this gas. The firm sale commitments are a crucial part in determining the reserves that can be booked regarding this field.

Dingo. Dingo is a gas field discovered in 1981. Four appraisal wells drilled between 1981 and 1990 established the field's resource and production potential. Until recently, Australian gas market dynamics have prevented the full development of Dingo as a producing field and the construction of the 33-mile tie-in to the Amadeus-Darwin Gas Pipeline. Magellan maintains its interest in Dingo through Retention License No. 2, which expires in February 2014 but is subject to renewal for a further five years. No mandatory capital expenditure is required until new gas sales contracts are secured.

Australia - NT/P82

In the Timor Sea, offshore Northern Territory, Australia, Magellan holds a 100% interest in the exploration permit NT/P82, which covers 2,500 square miles of the Bonaparte Basin in water ranging in depth from 30 to 500 feet. Under the terms of the permit, which is due to expire in May 2016, the Company is committed to shoot a minimum of 46 square miles of 3-D and 62 miles of 2-D seismic in 2012 and to drill a well by 2015.

United Kingdom

In the Weald and Wessex Basins, Magellan has interests in 11 Production Exploration and Development Licenses ("PEDLs"), representing a total of approximately 240,000 net acres onshore and offering both oil and gas prospects through conventional and unconventional development.

Magellan's acreage position is composed of three groups of PEDLs: (i) four licenses co-owned 50% with, and operated by, Celtique Energie, (ii) four licenses with varying ownership operated by Northern Petroleum, and (iii) three licenses wholly owned and operated by Magellan. To date in the United Kingdom, Magellan has participated in conventional wells, the most recent being the Markwells Wood-1, which was drilled and operated by Northern in PEDL 126. In addition, Magellan has contributed, along with its partners, to the exploration of its other licenses in accordance with the terms of each PEDL.

RESERVES

Estimates of reserves are inherently imprecise and continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

The below table presents a summary of our proved and probable reserves as of June 30, 2012.

	Oil (Mbbls)	Gas (MMcf)	Total (Mboe)[1]
Proved developed producing (PDP):			
United States	1,136	—	1,136
Australia	—	6,514	1,086
Total	1,136	6,514	2,222
Proved developed not producing (PDNP):			
United States	511	—	511
Australia	—	4,979	830
Total	511	4,979	1,341
Proved undeveloped (PUD):			
United States	7,258	—	7,258
Australia	—	—	—

Total	7,258	—	7,258
Total proved reserves	8,905	11,493	10,821

(1) Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

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	Oil (Mbbls)	Gas (MMcf)	Total (Mboe)[1]
PDP%	13 %	57 %	21 %
PDNP%	6 %	43 %	12 %
PUD%	81 %	— %	67 %
Probable:			
Developed	—	3,759	627
Undeveloped	4,097	10,065	5,775
Total	4,097	13,824	6,402
Total proved and probable reserves	13,002	25,317	17,223
Proved %	68 %	45 %	63 %
Probable %	32 %	55 %	37 %

[1] Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

As of June 30, 2012, our consolidated total proved reserves amounted to 10,821 Mboe, comprised of 8,905 Mbbls (68%) of proved oil reserves and 11,493 MMcf (45%) of proved gas reserves. All of our proved and probable oil reserves relate to our interest in Poplar, Montana. Of the 8,905 Mbbls of proved oil reserves, approximately 8,681 Mbbls (97%), 186 Mbbls (2%), and 38 Mbbls (1%) were derived from the Charles, Amsden, and Tyler formations, respectively.

As of June 30, 2012, all of our proved and probable gas reserves related to our interest in Palm Valley in Australia. Under the terms of the gas sales contract with Santos, we are entitled to sell up to approximately 22,500 MMcf of gas from Palm Valley to Santos, who on-sells the gas to third-party customers. As of June 30, 2012, proved gas reserves totaled 11,493 MMcf, corresponding to gas sales volumes committed to third-party customers under the Santos gas contract. The 13,824 MMcf of probable gas reserves correspond to the remaining volumes to be sold under the Santos gas contract plus additional volumes of gas estimated to be economically recoverable from Palm Valley.

Proved Undeveloped Reserves

As of June 30, 2012, we had 7,258 Mboe of proved undeveloped reserves, representing an increase of 317 Mboe, or 5%, over the prior year figure. This increase is the result of 1,247 Mboe added through Magellan's consolidation of its ownership in Poplar in September 2011, partially offset by a 721 Mboe reduction due to quantity revisions. During the fiscal year, we did not convert any proved undeveloped reserves to proved developed reserves.

As of June 30, 2012, we had no proved undeveloped reserves that had been on our books in excess of five years, and we recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well.

Probable Reserves

Estimates of probable developed and undeveloped reserves are inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that is as likely as not to be achieved. Estimates of probable reserves are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Internal Controls Over Reserve Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with regulations established by the U.S. Securities and Exchange Commission

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("SEC"). The Company relies upon a combination of internal technical staff and third party consulting arrangements for reserve estimation and review.

In the United States, the responsibility for reserves estimation is delegated to Blaine Spies, Magellan's Operations Manager since December 2011. Mr. Spies has over 19 years of operation and technical engineering experience in the oil and gas industry. Prior to his appointment with Magellan, Mr. Spies was the Operations Manager at American Oil & Gas, responsible for drilling and completion operations in North Dakota. Mr. Spies also has experience in the Rocky Mountain region working for Halliburton. He received his Bachelors of Science in Petroleum Engineering from the Colorado School of Mines and his Masters in Business Administration from the Colorado Technical University.

In Australia, reserve estimates were prepared by the Ryder Scott Company ("RS"), an independent petroleum engineering firm, in accordance with the Company's internal control procedures, which include the verification of input data used by RS, as well as management review and approval.

Third Party Reserve Audit

In the United States, reserve estimates were audited by Allen & Crouch Petroleum Engineers ("A&C"), an independent petroleum engineering firm. A copy of the summary reserve report of A&C is provided as Exhibit 99.1 to this Annual Report on Form 10-K. A&C does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis. In addition, A&C served as the reserves auditor for Jonah Bank of Wyoming with respect to NP's loan currently outstanding with Jonah Bank of Wyoming.

In Australia, reserve estimates were prepared by RS, an independent petroleum engineering firm. A copy of the summary reserve report of RS is provided as Exhibit 99.2 to this Annual Report on Form 10-K. RS does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

Detailed information regarding reserves, costs of oil and gas activities, capitalized costs, discounted future net cash flows, and results of operations is disclosed in the supplemental information, see Note 13, to the consolidated financial statements of this Form 10-K.

VOLUMES AND REALIZED PRICES

The following table summarizes volumes and prices realized from the sale of oil and gas from properties in which we owned an interest during the periods stated. The table also summarizes operational costs per barrel of oil equivalent.

	Volumes			Average realized price (2)			Production
	Oil	Gas	Total	Oil	Gas	Total	costs (3)
	(Mbbls)	(MMcf)	(Mboe)(1)	(Per bbl)	(Per Mcf)	(Per boe)(1)	(Per boe)(1)
Fiscal year ended June 30, 2012							
United States	75	—	75	$82.66	$—	$82.66	$70.06
Australia	45	434	119	$137.21	$3.11	$64.40	$65.13
All other areas	2	—	2	*	$—	*	$—
Total	122	434	196	$101.64	$3.11	$70.95	$66.47
2011							
United States	68	—	68	$77.96	$—	$77.96	$43.85
Australia	55	712	174	$98.60	$2.26	$47.27	$36.10
Total	123	712	242	$96.11	$2.26	$56.27	$38.28
2010							
United States	42	—	42	$67.88	$—	$67.88	$36.44
Australia	68	3,430	640	$75.46	$4.47	$31.22	$12.83
All other areas	29	—	29	*	$—	*	$—
Total	139	3,430	711	$70.75	$4.47	$33.02	$13.67

(*) Not meaningful.
(1) Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

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(2) Prices per bbl or per Mcf are reported net of royalties. However, it should be noted that current period prices may be influenced by prior period royalty adjustments arising from annual royalty audits.
(3) Production cost excludes ad valorem and severance taxes.
Total production declined from 242 Mboe in fiscal year 2011 to 196 Mboe in fiscal year 2012, primarily as a result of the Palm Valley PWC contract termination in January 2012, which also contributed to the decline of gas production from 712 MMcf to 434 MMcf in fiscal year 2012. Production cost on a $/boe basis increased in Australia from $36.10/boe to $65.13/boe primarily due to decreased production, and increased in the United States from $43.85/boe to $70.06/boe primarily due to a material increase in workovers without a corresponding increase in production volumes. These factors combined to increase production costs from $38.28/boe to $66.47/boe in the United States and Australia.

PRODUCTIVE WELLS

Productive wells include producing wells and wells mechanically capable of production. In Australia, all gas wells were located at Palm Valley. The following table presents a summary of our productive wells by geography as of June 30, 2012.

	Oil Wells		Gas Wells		Total Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
United States	39.0	37.4	—	—	39.0	37.4
Australia	—	—	1.0	1.0	1.0	1.0
Total	39.0	37.4	1.0	1.0	40.0	38.4

(1) A gross well is a well in which the Company owns a working interest. Wells with one or more completions in the same bore hole are considered to be one well.
(2) The number of net wells is the sum of the fractional working interests owned in gross wells.

DRILLING ACTIVITY

The following table summarizes the results of our development and exploratory drilling during the years ended:

	June 30, 2012		2011		2010	
	Productive [2]	Dry [3]	Productive [2]	Dry [3]	Productive [2]	Dry [3]
Development wells, net [1]:						
United States	4.0	1.0	1.0	—	—	—
Australia	—	—	—	—	0.4	—
Total	4.0	1.0	1.0	—	0.4	—
Exploratory wells, net [1]:						
United States	1.0	—	—	—	—	—
Australia	—	—	—	—	—	0.9
Total	1.0	—	—	—	—	0.9
Total net wells	5.0	1.0	1.0	—	0.4	0.9

(1) The number of net wells is the sum of the fractional working interests owned in gross wells. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.
(2) A productive well is an exploratory, development, or extension well that is not a dry well.
(3) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. Completion refers to installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been plugged and abandoned.

Out of the five productive wells completed during the current fiscal year, the EPU 117 was classified as an exploratory well, and the remaining four wells were comprised of four recompletions of existing wells at Poplar. The dry well was an unsuccessful recompletion of a well at Poplar.

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The following table summarizes the results, as of September 24, 2012, of our wells that were still in progress as of June 30, 2012.

	Still in Progress	
	Gross [(1)]	Net [(2)]
United States	1.0	1.0
All other areas	1.0	0.4
Total	2.0	1.4

(1) A gross well is a well in which the Company owns a working interest. Wells with one or more completions in the same bore hole are considered to be one well.
(2) The number of net wells is the sum of the fractional working interests owned in gross wells.
The one well still in progress in the United States is the EPU 119, which is still being evaluated for CO_2 stimulation and possible conversion into an injection well.

ACREAGE
The following table summarizes gross and net developed and undeveloped acreage by geographic area at June 30, 2012.

	Developed [(1)]		Undeveloped [(4)]		Total	
	Gross [(2)]	Net [(3)]	Gross [(2)]	Net [(3)]	Gross [(2)]	Net [(3)]
United States						
Poplar	22,913	22,035	—	—	22,913	22,035
Australia						
Palm Valley	41,644	41,644	116,288	116,288	157,932	157,932
Dingo	—	—	116,139	116,139	116,139	116,139
NT/P82	—	—	1,566,647	1,566,647	1,566,647	1,566,647
All other areas						
United Kingdom	—	—	410,909	241,769	410,909	241,769
Total	64,557	63,679	2,209,983	2,040,843	2,274,540	2,104,522

(1) Developed acreage encompasses those leased acres assignable to productive wells. Our developed acreage that includes multiple formations may be considered undeveloped for certain formations but have been included as developed acreage in the presentation above.
(2) A gross acre is an acre in which the registrant owns a working interest.
(3) The number of net acres is the sum of the fractional working interests owned in gross acres.
(4) Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.
Of our 22,913 gross acres at Poplar, approximately 18,000 acres (78%) form a Federal Exploratory Unit which is held by production from any one well. Currently, Poplar contains 39 producing wells.

TITLES TO PROPERTY, PERMITS, AND LICENSES
Magellan maintains interests in its oil and gas properties through various contractual arrangements customary to the oil and gas industry and relevant to the local jurisdictions of its assets.
United States
In the United States, Magellan maintains its working interests in oil and gas properties pursuant to leases from third parties. We have either commissioned title opinions or conducted title reviews on substantially all of our properties and believe we have title to them. Magellan obtains title opinions to a drill site prior to commencing initial drilling operations. In accordance with industry practice, we perform only minimal title review work at the time of acquiring undeveloped properties.
Australia

In Australia, all of Magellan's onshore permits are issued by the Northern Territory and are subject to the Petroleum (Prospecting and Mining) Act and the Petroleum Act of the Northern Territory. Lessees have the exclusive right to produce petroleum from the land subject to payment of a rental and a royalty at the rate of 10% of the wellhead value of the petroleum

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produced. Rental payments may be offset against the royalty paid. The term of a petroleum lease is typically 21 years, and leases may be renewed for successive terms of 21 years each.

The below table summarizes the permits we maintain in Australia as of June 30, 2012.

Permit	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres (1)	Net acres (2)
Petroleum Lease No. 3 (Palm Valley)	Amadeus	11/7/2024	Magellan	100%	157,932	157,932
Retention License No. 2 (Dingo)	Amadeus	2/16/2014	Magellan	100%	116,139	116,139
NT/P82 (Timor Sea)	Bonaparte	5/12/2016	Magellan	100%	1,566,647	1,566,647
Total					1,840,718	1,840,718

(1) A gross acre is an acre in which the registrant owns a working interest.

(2) The number of net acres is the sum of the fractional working interests owned in gross acres.

United Kingdom

In the United Kingdom, Petroleum Exploration and Development Licenses issued by the government are subject to the Petroleum Act. Licensees have the exclusive right to produce petroleum from the land subject to payment of a rental. The maximum term of the license is 31 years. Licenses expire after the initial exploration term of 6 years if a well is not drilled and after 11 years if a well is drilled but no development program is approved by the Secretary of State for Energy and Climate Change.

The below table summarizes the permits we maintain in the United Kingdom as of June 30, 2012.

License	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres (1)	Net acres (2)
PEDL 126	Weald	6/30/2014	Northern	40%	30,124	12,050
PEDL 135	Weald	9/30/2012	Magellan	100%	49,147	49,147
PEDL 137	Weald	9/30/2013	Magellan	100%	24,525	24,525
PEDL 155	Weald	9/30/2015	Northern	40%	13,029	5,212
PEDL 231	Weald	6/30/2014	Celtique	50%	98,880	49,440
PEDL 232	Weald	6/30/2014	Celtique	50%	23,342	11,671
PEDL 234	Weald	6/30/2014	Celtique	50%	74,100	37,050
PEDL 240	Wessex	6/30/2014	Northern	23%	1,778	409
PEDL 243	Weald	6/30/2014	Celtique	50%	74,100	37,050
PEDL 246	Weald	6/30/2014	Magellan	100%	10,769	10,769
PEDL 256	Weald	4/30/2015	Northern	40%	11,115	4,446
Total					410,909	241,769

(1) A gross acre is an acre in which the registrant owns a working interest.

(2) The number of net acres is the sum of the fractional working interests owned in gross acres.

The PEDL 135 license, representing 49,147 gross and net acres, is due to expire in September 2012 and is unlikely to be renewed, thereby reducing our gross and net acres in the United Kingdom to 361,762 and 192,622 acres, respectively. Following the exploration work conducted with Celtique, management does not consider this license to be core to our strategy due to its location and assessed potential.

MARKETING ACTIVITIES AND CUSTOMERS

Customers

United States. In the United States, the Company has a sole customer who accounted for 45%, 30%, and 8% of the consolidated revenues during the fiscal years ended June 30, 2012, 2011, and 2010, respectively.

Australia. In Australia, revenue from one customer accounted for approximately 45%, 35% , and 25% of consolidated revenues for the years ended June 30, 2012, 2011, and 2010, respectively; revenue from another customer accounted for approximately 8%, 11%, and 10% of consolidated revenues in the same periods, respectively.

Delivery Commitments

Our production sales agreements contain customary terms and conditions with various parties that require us to deliver a fixed determinable quantity of product. During September 2011, Magellan entered into a Gas Supply and Purchase Agreement

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(the "Santos Gas Contract") with the Santos Entities. The terms of the Santos Gas Contract commenced upon completion of the Santos SA and provide for the sale by Magellan to the Santos Entities of a total contract gas quantity of 25.65 Petajoules over the 17 year term of the Santos Gas Contract, subject to certain limitations regarding deliverability into the Amadeus Pipeline. We are not obliged to deliver fixed quantities of gas under the Santos Gas Contract other than that which we forecast for delivery over the ensuing 12 months. We can re-forecast quantities of gas every three months for the remainder of the contract year. If a shortfall in delivery of more than 10% occurs on any daily nomination by Santos, and confirmed for delivery by us, we incur a shortfall. If we shortfall on deliveries we can provide make-up gas in years 16 and 17 of the contract term. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, we have certain rights to arrange for third party gas to be delivered into the gathering lines and such volume will count towards our minimum commitment. We believe our production and reserves are adequate to meet these delivery commitments.

CURRENT MARKET CONDITIONS AND COMPETITION

Seasonality of Business

Demand and prices for oil and gas can be impacted by seasonal factors. Increased demand for heating oil in the winter and gasoline during the summer driving season can positively impact oil price during those times. Increased demand for heating and air conditioning can positively impact the price of natural gas during the winter and summer months, respectively. Unusual weather patterns can increase or dampen normal price levels. Our ability to carry out drilling activities can be adversely affected by weather conditions during winter months at Poplar. In general, the Company's working capital balances are not materially impacted by seasonal factors. In Australia, gas supply contracts are generally long term fixed price contracts and are unaffected by seasonality.

Competitive Conditions in the Business

The oil and gas industry is highly competitive. We face competition from numerous major and independent oil and gas companies, many of whom have greater technical, operational, and financial resources, or who have vertically integrated operations in areas such as pipelines and refining. Our ability to compete in this industry depends upon such factors as our ability to identify and economically acquire prospective oil and gas properties; the geological, geophysical, and engineering capabilities of management; the financial strength and resources of the Company; and our ability to secure drilling rigs and other oil field services in a timely and cost-effective manner. We believe our acreage positions, our management's technical and operational expertise, and the strength of our balance sheet allow us to effectively compete in the exploration and development of oil and gas projects.

The oil and gas industry itself faces competition from alternative fuel sources, which include other fossil fuels, such as coal and renewable energy sources.

EMPLOYEES AND OFFICE SPACE

As of June 30, 2012, the Company had 35 total employees. We maintain approximately 6,000 square feet of functional office space in Denver, Colorado, for our executive and administrative headquarters and 4,435 square feet of office space in Brisbane, Australia.

GOVERNMENT REGULATIONS

Regulations Applicable to Foreign Operations

Many of the properties in which we have interests are located outside of the United States, and are subject to foreign laws, regulations, and related risks involved in the ownership, development, and operation of those foreign property interests. Foreign laws and regulations may result in possible nationalization of assets, expropriation of assets, confiscatory taxation, changes in foreign exchange controls, currency revaluations, price controls or excessive royalties, export sales restrictions, and limitations on the transfer of interests in exploration licenses. In addition, foreign laws and regulations providing for conservation, proration, curtailment, cessation, or other limitations or controls on the production of or exploration for hydrocarbons may increase the costs or have other adverse effects on our foreign operations. As a result, an investment in us is subject to foreign regulatory risks in addition to those risks inherent in U.S. domestic oil and gas exploration and production company investments.

Our Australian operations are subject to stringent Australian laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations, which include the Environment Protection and Biodiversity Conservation Act 1999, require the acquisition of approvals before seismic acquisition or drilling commences, restrict the types, quantities, and concentration of substances that can be released into the

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environment in connection with drilling and production activities, limit or prohibit seismic or drilling activities in protected areas, and impose substantial liabilities for pollution resulting from oil and gas operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Changes in Australian environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal, or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release of such materials or if our operations were standard in the industry at the time they were performed.

Energy Regulations

Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for, and production of, oil and gas, including laws and regulations requiring permits for the drilling of wells; imposing bonding requirements in order to drill or operate wells; and governing the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, state conservation laws sometimes establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM") and/or the Bureau of Indian Affairs ("BIA"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM or the BIA can suspend or terminate our operations on federal or Indian leases.

Environmental, Health, and Safety Matters

General. Our operations are subject to stringent and complex federal, state, tribal, and local laws and regulations governing protection of the environment and worker health and safety as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly permitting, waste handling, disposal, and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules, and regulations to which our business is subject:

Waste handling. The Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes.

Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

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Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers, or analogous state agencies. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air emissions. The federal Clean Air Act ("CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. See Item 1A, Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and gas. In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intensive storms and flooding, and could adversely affect the demand for our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our well drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas. National Environmental Policy Act. Oil and natural gas exploration and production activities on federal and Indian lands are subject to the National Environmental Policy Act (the "NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal and Indian lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay development of some of our oil and natural gas projects.

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OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. While we do not routinely utilize hydraulic fracturing techniques in our drilling and completion programs, that may change in the future if we embark on a successful Bakken/Three Forks play in Poplar. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques which could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs, and delays which could adversely affect our financial position, results of operations, and cash flows. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We cannot give any assurance that we will not be adversely affected in the future.

AVAILABLE INFORMATION

Our internet website address is www.magellanpetroleum.com. We routinely post important information for investors on our website, including updates about us and our operations. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available within our website's corporate governance section the by-laws, code of conduct, and charters for the Audit Committee and the Compensation, Nominating and Governance Committee of the Board of Directors of Magellan Petroleum Corporation. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATION

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) attributable to Magellan, plus (i) depletion, depreciation, amortization, and accretion expense, (ii) exploration expense, (iii) stock based compensation expense, (iv) foreign transaction loss (gain), (v) impairment expense, (vi) loss on Evans Shoal, (vii) gain on sale of assets, (viii) warrant expense, (ix) net interest income, (x) other income, (xi) income tax benefit (provision), and net (loss) income attributable to non-controlling interest in subsidiaries. Adjusted EBITDAX is not a measure of net income or cash flow as determined by accounting principles generally accepted in the United States ("GAAP"), and excludes certain items that we believe affect the comparability of operating results.

Our Adjusted EBITDAX measure provides additional information which may be used to better understand our operations. Adjusted EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of

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our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as the historic cost of depreciable and depletable assets. Adjusted EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, Adjusted EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to historical cost basis and items affecting the comparability of period to period operating results.

The following table provides a reconciliation of net income (loss) to Adjusted EBITDAX for the years ended:

	June 30,		
	2012	2011	2010
	(In thousands)		
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)
Depletion, depreciation, amortization, and accretion expense	1,744	2,890	5,428
Exploration expense	6,291	2,854	1,273
Stock based compensation expense	1,560	1,670	2,305
Foreign transaction (gain) loss	(475)	951	677
Impairment expense	328	173	2,050
Loss on Evans Shoal	—	15,893	—
Gain on sale of assets	(40,413)	(969)	(6,817)
Warrant expense	—	—	4,276
Net interest income	(749)	(923)	(1,038)
Other income	(9)	—	(1,975)
Income tax (benefit) provision	(5,951)	5,141	2,646
Net (loss) income attributable to non-controlling interest in subsidiaries	(15)	(5)	(11)
Adjusted EBITDAX	$(11,191)	$(4,757)	$7,368

ITEM 1A: RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us. These risk factors and other uncertainties may cause our actual future results to differ from those expressed or implied in the forward-looking statements contained in this report and in other public statements we make. In addition, because of these risks and uncertainties, as well as other variables affecting our operating results, our past financial performance should not be considered to be indicative of future performance.

RISKS RELATING TO OUR BUSINESS

Our principal producing oil and gas properties in the Poplar and Palm Valley fields may stop producing oil and gas.

Our principal producing properties are located in the Poplar field in Montana and the Palm Valley field in Australia, and are subject to risks associated with regional supply and demand factors and potential delays or interruptions of production from wells in these areas resulting from governmental regulations, processing or transportation capacity constraints, and the availability of equipment, facilities, personnel, or services. Due to the relatively concentrated nature of our portfolio of producing properties, a number of our properties could experience any of the same conditions at the same time, resulting in relatively greater impact on our results of operations and cash flows than they might have on other companies that have a more diversified portfolio of properties. As a result of these risks, our producing properties may stop producing oil and gas, or there could be a material decrease in production levels at these fields. Since these properties are currently our principal revenue producing properties, any decline in production levels at these properties could have a material adverse effect on our revenues, results of operations, and cash flows. Any such adverse impact on our revenues and cash flows may restrict our ability to explore and develop oil and gas properties in the future and cause our stock price to decline.

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Our Palm Valley production revenues and cash flows depend on a long-term gas sales agreement.
In 2012, we entered into a long-term sales agreement with Santos to sell up to approximately 23 Bcf of natural gas from our properties in the Palm Valley field over the next 17 years to Santos, who on-sells the gas to third party customers. As of June 30, 2012, there were two customers receiving gas from Palm Valley. In the event this agreement becomes uneconomic or is unexpectedly breached or terminated or designated quantities are decreased as permitted under the contract terms, our revenues and cash flows could be adversely impacted, and our current niche strategy of marketing Amadeus Basin gas to the mining industry in central Australia may not be successful.
Our Poplar production revenues and cash flows depend on one purchaser, and the inability of the purchaser to meet its payment obligations to us may adversely affect our financial results.
Currently, we rely on an agreement with Plains Marketing, LP as the sole purchaser of our oil production at Poplar. If this purchaser reduces or discontinues its business with us, or if we are unable to successfully negotiate a replacement agreement with this purchaser, who can terminate services with a 90 day notice period, or if the replacement agreement is on less favorable terms, the effect on us could be adverse if we are unable to obtain new purchasers for the oil produced at Poplar. In addition, if this purchaser were to experience financial difficulties or any deterioration in its ability to satisfy its obligations to us, our revenues and cash flows from Poplar could be adversely affected.
Our CO_2-EOR project at Poplar may not be successful.
We believe that the Charles formation in the Poplar field is a potential candidate for a CO_2-EOR project, whereby CO_2 is injected into a reservoir to enhance oil recovery. While laboratory analyses and preliminary tests indicate that a CO_2-EOR project at Poplar is potentially viable, the additional production and reserves that may result from CO_2-EOR methods are inherently difficult to predict. If the CO_2-EOR project does not allow for the extraction of oil in the manner or to the extent that we anticipate, our future results of operations, cash flows, and financial condition could be materially adversely affected. In addition, our ability to utilize CO_2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. If we are limited in the quantities of CO_2 available to us, we may not have sufficient CO_2 to produce oil in the manner or to the extent that we anticipate, and our future oil production volumes could be negatively impacted.
Our acquisitions of our investments in new oil and gas properties or other assets may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.
Successful property or other acquisitions or investments require an assessment of a number of factors sometimes beyond our control. These factors include exploration potential, future crude oil and natural gas prices, operating costs, and potential environmental and other liabilities. These assessments are not precise, and their accuracy is inherently uncertain.
In connection with our acquisitions, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties.
In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.
Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.
These factors could have a material adverse effect on our business, financial condition, results of operations, and cash flows. Consideration paid for any future acquisitions could include our stock or require that we incur additional debt and contingent liabilities. As a result, future acquisitions could cause dilution of existing equity interests and earnings per share.

Exploration and development drilling may not result in commercially producible reserves.
Crude oil and natural gas drilling and production activities are subject to numerous risks, including the risk that no commercially producible crude oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and crude oil or natural gas drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;

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- title problems;
- disputes with owners or holders of surface interests on or near areas where we intend to drill;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, equipment, pipe, water, and other supplies.

The prevailing prices for crude oil and natural gas affect the cost of and demand for, drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. In addition, the recent economic and financial downturn has adversely affected the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

Another significant risk inherent in drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells.

The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if crude oil or natural gas is present, or whether it can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling and completion costs.

Our future drilling activities may not be successful. Although we have identified potential drilling locations, we may not be able to economically produce oil or natural gas from them.

We may not be successful in sharing the exploration and development costs of the fields and permits in which we hold interests.

Our drilling plans depend, in certain cases, on our ability to enter into farm-in, joint venture, or other cost sharing arrangements with other oil and gas companies. If we are not able to secure such farm-in or other arrangements in a timely manner, or on terms which are economically attractive to the Company, we may be forced to bear higher exploration and development costs with respect to our fields and interests. We may also be unable to fully develop and/or explore certain fields if the costs to do so would exceed our available exploration budget and capital resources. In either case, our results of operations could be adversely affected and the market price of our common shares could decline.

The loss of key personnel could adversely affect our ability to operate.

We depend, and will continue to depend in the foreseeable future, on the services of our executive management team and other key personnel. The ability to retain officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen, and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

There are risks inherent in foreign operations, such as adverse changes in currency values and foreign regulations relating to MPAL's exploration and development operations and to MPAL's payment of dividends to Magellan.

The properties in which we have interests located outside the United States are subject to certain risks related to the indirect ownership and development of foreign properties, including government expropriation and nationalization, adverse changes in currency values and foreign exchange controls, foreign taxes, U.S. taxes on the repatriation of funds to the United

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States, and other laws and regulations, any of which may have a material adverse effect on our properties, financial condition, results of operations, or cash flows. Although there are currently no exchange controls on the payment of dividends to Magellan by MPAL, such payments could be restricted by Australian foreign exchange controls, if implemented.

We have limited management and staff and will be dependent upon partnering arrangements.

We had 35 total employees as of June 30, 2012. Due to our limited number of employees, we expect that we will continue to require the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental, and tax services. We also plan to pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation, and prospect leasing. Our dependence on third party consultants and service providers creates a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and
- the risk that we may not be able to properly control the timing and quality of work conducted with respect to our projects.

If we experience significant delays in obtaining the services of such third parties or poor performance by such parties, our results of operations and stock price will be materially adversely affected.

Oil and gas prices are volatile. A decline in prices could adversely affect our financial condition, results of operations, cash flows, access to capital, and ability to grow.

Our revenues, results of operations, future rate of growth, and the carrying value of our oil and gas properties depend primarily upon the prices we receive for the oil and gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The prices of oil and natural gas have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to numerous factors, including the following:

- worldwide and domestic supplies of oil and gas, and the productive capacity of the oil and gas industry as a whole;
- changes in the supply and demand for such fuels;
- overall global and domestic economic conditions;
- political conditions in oil, natural gas, and other fuel-producing and fuel-consuming areas;
- the extent of Australian domestic oil and gas production and importation of such fuels and substitute fuels in Australian and other relevant markets;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil or natural gas;
- weather conditions, including effects of weather conditions on prices and supplies in worldwide energy markets;
- technological advances affecting energy consumption;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude oil prices and production controls;
- the competitive position of each such fuel as a source of energy as compared to other energy sources;
- strengthening and weakening of the United States dollar relative to other currencies; and
- the effect of governmental regulation and taxes on the production, transportation, and sale of oil, natural gas, and other fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Furthermore, the ongoing worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession would likely reduce worldwide demand for energy and result in lower oil and natural gas prices. Oil prices declined from previous years' record levels to below $70 per barrel in August 2009, and then have increased to $97 per barrel in August 2012, while natural gas prices have declined from over $13 per Mcf to approximately $3 per Mcf over the same period.

Sustained declines in oil and gas prices would not only reduce our revenues but also could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows, and reserves. Further, oil and gas prices do not necessarily move in tandem. Gas sales contracts in Australia are adjusted to the gas price movements related to the Australian Consumer Price Index. Future gas sales not

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governed by existing contracts would generate lower revenue if natural gas prices in Australia were to decline. Sales of our proved oil reserves are dependent on world oil prices. The volatility of these prices will affect future oil revenues.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration, and production, and face intense competition from both major and other independent oil and natural gas companies. Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties, and consummate transactions in this highly competitive environment. In addition, we may not be able to compete with, or enter into cooperative relationships with, any such firms.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

U.S. federal, state, tribal, and local authorities, and corresponding Australian governmental authorities, extensively regulate the oil and natural gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing or marketing of crude oil and natural gas production. Noncompliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of crude oil and natural gas, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in crude oil and natural gas properties, rights-of-way and easements, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, and restoration standards, oil and gas operations, and restoration. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Governmental authorities also may require any of our ongoing or planned operations on their leases or licenses to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a material adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between various regulatory agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several liability or strict liability under federal, state, and tribal environmental laws for noise emissions and for discharges of crude oil, natural gas, and associated liquids or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs but also natural resources, real or personal property, and other compensatory damages and civil and criminal liability. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a material adverse effect on us.

The potential impacts of global warming and climate change may have an adverse effect on our operations and the demand for crude oil and natural gas.

Global warming and climate change have become the subject of an important public policy debate. Climate change remains a complex issue, with some scientific research suggesting that an increase in greenhouse gas emissions may contribute to the warming of the earth's atmosphere and other climatic changes and pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations.

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International agreements and national or regional legislation and regulatory measures to limit greenhouse gas emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies, and regulations may result in substantial capital, compliance, operating, and maintenance costs. For example, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition, results of operations, and cash flows.

In addition, some scientists have predicted that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operations or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

This report and the documents incorporated by reference in this report contain estimates of our proved and probable reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and gas reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and gas prices, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production by operators on adjacent properties. Probable reserves are less certain to be recovered than proved reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on the average, first-day-of-the-month price during the 12-month period preceding the measurement date. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production;

- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows for financial statement disclosure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

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Reserves as of June 30, 2012, have been reported under SEC rules. The estimates provided in accordance with the SEC rules may change materially as a result of interpretive guidance that may be subsequently released by the SEC. We have included in this report estimates of our proved reserves at June 30, 2012, as prepared consistent with our independent reserve engineers' interpretations of the SEC rules relating to disclosures of estimated natural gas and oil reserves. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. While the estimates of our proved reserves at June 30, 2012, included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could ultimately differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

We may be limited in our ability to book additional proved undeveloped reserves under the SEC rules.

Another impact of the SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program on our undeveloped properties.

We may not have funds sufficient to make the significant capital expenditures required to replace our reserves.

Our exploration, development, and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, farming-in other companies or investors to our exploration and development projects in which we have an interest, and/or equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to rely upon additional farm-in opportunities, debt or equity offerings, or other methods of financing to meet these cash flow requirements.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop, or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration, or acquisition activities, our reserves will decline over time. Recovery of any additional reserves will require significant capital expenditures and successful drilling operations. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

Future price declines may result in a write-down of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas operations. Under this method, the costs of successful wells, development dry holes, and productive leases are capitalized and amortized on a units-of-production basis over the life of the related reserves. Cost centers for amortization purposes are determined on a field-by-field basis. We record our proportionate share in joint venture operations in the respective classifications of assets, liabilities, and expenses. Unproved properties with significant acquisition costs are periodically, but at least annually, assessed for impairment in value with any required impairment charged to expense. The successful efforts method also imposes limitations on the carrying or book value of proved oil and gas properties. Oil and gas properties (including exploration rights), along with goodwill, are reviewed for impairment annually or whenever events or circumstances indicate that the carrying amounts may not be recoverable. In general, analyses are based on proved developed reserves, except in circumstances where it is probable that additional resources will be developed and contribute to cash flows in the future. For Palm Valley, future undiscounted cash flows were based upon the quantities of gas currently committed to the current contract and estimated sales subsequent to the contract. If such new contracts are effected, the proved developed reserves will be increased to the lesser of the current risk adjusted probable and possible reserves or the newly contracted quantities. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future write down of capitalized costs and a non-cash charge against future earnings.

Oil and gas drilling and producing operations are hazardous and expose us to environmental liabilities.

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, and other environmental hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings, and separated cables. If any of these risks occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to, or destruction of, property, natural resources, and equipment;

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- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties;
- suspension of operations;
- and compliance with, or changes in, environmental laws and regulations relating to air emissions, waste disposal and hydraulic fracturing, laws and regulations imposing conditions and restrictions on drilling and completion operations, and other laws and regulations, such as tax laws and regulations.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. We maintain insurance against some, but not all, of the risks described above. Our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Difficult conditions resulting from the ongoing U.S. and worldwide financial and credit crisis and significant concerns over the continuing recessions in the U.S. economy may materially adversely affect our business and results of operations, and we do not expect these conditions to improve in the near future.

Continual volatility and disruption since 2008 in worldwide capital and credit markets and further deteriorating conditions in the U.S. and Australian economies could affect our revenues and earnings negatively and could have a material adverse effect on our business, results of operations, and financial condition. For example, purchasers of our oil and gas production may reduce the amounts of oil and gas they purchase from us and/or delay or be unable to make timely payments to us.

Further, a number of our oil and gas properties are operated by third parties whom we depend upon for timely performance of drilling and other contractual obligations and, in some cases, for distribution to us of our proportionate share of revenues from sales of oil and gas we produce. If current economic conditions adversely impact our third party operators, we are exposed to the risk that drilling operations or revenue disbursements to us could be delayed. This "trickle down" effect could significantly harm our business, financial condition, results of operations, and cash flows.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non-operated properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements, or an operator's failure to act in ways that are in our best interests could reduce our production, revenues, and reserves. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator's:

- nature and timing of drilling and operational activities;
- timing and amount of capital expenditures;
- expertise and financial resources;
- the approval of other participants in drilling wells; and
- selection of suitable technology.

Currency exchange rate fluctuations may negatively affect our operating results.

The exchange rates among the Australian dollar and the U.S. dollar, as well as the exchange rates between the Australian dollar and the British pound, have changed in recent periods and may fluctuate substantially in the future. We expect that a majority of our revenue will be denominated in U.S. dollars in the future. However, at June 30, 2012, the U.S. dollar has strengthened against the Australian dollar which has had, and may continue to have, a negative impact on our revenues generated in the Australian dollar, as well as our operating income and net income, as considered on a consolidated basis. The foreign exchange gain for the year ended June 30, 2012, was $1.0 million and is included in accumulated other comprehensive income on the balance sheet. Any appreciation of the U.S. dollar against the Australian dollar is likely to have a positive impact on our revenue, operating income, and net income. Because of our U.K. development program, a portion of our expenses, including exploration costs and capital and operating expenditures, will continue to be denominated in British pounds. Accordingly, any material appreciation of the British pound against the Australian dollar could have a negative impact on our business, operating results, and financial condition.

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Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations, and cash flows.

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws applicable to oil and natural gas exploration and production companies. These proposed changes include, but are not limited to:

- eliminating the immediate deduction for intangible drilling and development costs;
- eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development;
- repealing the percentage depletion allowance for oil and gas properties;
- extending the amortization period for certain geological and geophysical expenditures; and
- implementing certain international tax reforms.

These proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations, and cash flows.

RISKS RELATED TO OUR COMMON STOCK

Fluctuations in our operating results and other factors may depress our stock price.

During the past few years, the equity trading markets in the United States have experienced price volatility that has often been unrelated to the operating performance of particular companies. These fluctuations may adversely affect the trading price of our common shares. From time to time, there may be significant volatility in the market price of our common shares. Investors could sell shares of our common stock at or after the time that it becomes apparent that the expectations of the market may not be realized, resulting in a decrease in the market price of our common shares.

Our dividend policy could depress our stock price.

We have never declared or paid dividends on our common stock and have no current intention to change this policy. We plan to retain any future earnings to reduce our accumulated deficit and finance growth. As a result, our dividend policy could depress the market price for our common stock and cause investors to lose some or all of their investment.

We may issue a substantial number of shares of our common stock under our stock incentive plan, other equity grants, and our outstanding warrants, and shareholders may be adversely affected by the issuance of those shares.

As of June 30, 2012, there were 4,347,826 warrants outstanding and 6,753,125 stock options outstanding, of which 4,861,454 are fully vested and exercisable. As of that date, there were also 435,000 options available for future grants under our 1998 Stock Incentive Plan as amended in December of 2010. If all of these options and warrants, which total 11,100,951 in the aggregate, are awarded and exercised, shares received would represent approximately 21% of our outstanding common shares and would, upon their exercise and the payment of the exercise prices, dilute the interests of other shareholders and could adversely affect the market price of our common stock.

If our shares are delisted from trading on the NASDAQ Capital Market, their liquidity and value could be reduced.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market, the Company's shares must maintain a minimum bid price of $1.00 as set forth in Marketplace Rule 5550(a)(2). If the bid price of the Company's shares trade below $1.00 for 30 consecutive trading days, then the bid price of the Company's shares must trade at $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. On September 4, 2012, our shares closed at $1.17 per share, but our shares closed at below $1.00 on certain trading days in August 2012. If our shares were to be delisted from trading on the NASDAQ Capital Market, they may be eligible for trading on the OTCQB. The delisting of our shares from NASDAQ could adversely impact the liquidity and value of our shares.

Provisions in our charter documents and Delaware law may delay or prevent our acquisition by a third party.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various barriers to the ability of a third party to acquire control of us, even if a change of control would be beneficial to our existing stockholders. In addition, our certificate of incorporation and bylaws contain several provisions that may make it more difficult for a third party to acquire control of us without the approval of our board of directors. These provisions may make it more difficult or expensive for a third party to acquire a majority of our outstanding common stock. Among other things, these provisions:

- authorize us to issue preferred stock that can be created and issued by the board of directors without prior stockholder

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approval, with rights senior to those of common stock;
- classify our board of directors so that only some of our directors are elected each year;
- prohibit stockholders from calling special meetings of stockholders; and
- establish advance notice requirements for submitting nominations for election to the board of directors and for proposing matters that can be acted upon by stockholders at a meeting.

These provisions also may delay, prevent, or deter a merger, acquisition, tender offer, proxy contest, or other transaction that might otherwise result in our stockholders receiving a premium over the market price for their common stock.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

ITEM 3: LEGAL PROCEEDINGS

We may be involved from time to time in legal proceedings relating to disputes or claims arising out of our operations in the normal course of business. As of the filing date of this report, there are no pending legal proceedings that we believe could have a material adverse effect on our financial condition, results of operations, or cash flows.

ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5: MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

PRINCIPAL MARKET

The principal market for Magellan's common stock is the NASDAQ Capital Market. We trade under the symbol MPET. Our stock is also traded on the Australian Stock Exchange in the form of CHESS Depository Interests ("CDIs") under the symbol MGN. The below table presents the quarterly high and low prices on our most active market, NASDAQ, during the periods indicated. Each CHESS is matched by one Magellan common stock share. As of June 30, 2012, there were approximately 1,000,000 CDIs outstanding.

Quarter ended	High	Low
June 30, 2012	$1.39	$1.01
March 31, 2012	$1.49	$0.87
December 31, 2011	$1.24	$0.89
September 30, 2011	$1.89	$1.12
June 30, 2011	$2.58	$1.38
March 31, 2011	$3.45	$2.27
December 31, 2010	$3.03	$1.78
September 30, 2010	$1.97	$1.49

HOLDERS

As of September 7, 2012, the number of record holders of Magellan's common stock was 5,338; and, based upon inquiry, the number of beneficial owners was approximately 6,300, including approximately 1,100 who held beneficial ownership of shares through CHESS Depository Interests.

FREQUENCY AND AMOUNT OF DIVIDENDS

Magellan has never paid a cash dividend on its common stock. The Company does not intend to pay cash dividends in the foreseeable future.

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning June 30, 2007, and ending on June 30, 2012, with the cumulative total returns of the NASDAQ Composite Index, a broad equity market index, and the Morningstar Oil and Gas E&P Industry Index, an industry group index. The graph assumes a $100 investment made on July 1, 2007, and the reinvestment of all dividends.

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RECENT SALES OF UNREGISTERED SECURITIES

Unregistered Inducement Grants during the fiscal year ended June 30, 2012, that were outside of the 1998 Stock Incentive Plan, as amended, were reported in Form 8-Ks.

ISSUER PURCHASES OF EQUITY SECURITIES

The table below provides information about purchases of the Company's common stock by the Company during the periods indicated.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program
April 1, 2012 - April 30 , 2012	—	$—	—	319,150
May 1, 2012 - May 31, 2012	—	$—	—	319,150
June 1, 2012 - June 30, 2012	—	$—	—	319,150
Total	—	$—	—	319,150

On December 8, 2008, the Company announced that its Board of Directors had approved a stock repurchase plan whereby the Company was authorized to purchase up to one million shares of its common stock in the open market. Through June 30, 2012, the Company had purchased 680,850 of its shares under this plan at an average price of $1.01 per share, or a total cost of approximately $0.7 million, all of which shares have been canceled. No shares were purchased during 2012, 2011, or 2010. On September 24, 2012, the Company announced that its Board of Directors had approved a new stock repurchase program whereby the Company is authorized to repurchase up to a total of $2.0 million in shares of its common stock. This authorization supersedes the prior plan and will expire on August 21, 2014. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including compliance with securities laws. Stock repurchases may be funded with existing cash balances or internal cash flow. The stock repurchase program may be suspended or discontinued at any time.

ITEM 6: SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data for Magellan for the fiscal years ended as indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with Part II, Item 7: Management's Discussion and Analysis of Financial

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Condition and Results of Operations of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this Form 10-K.

	June 30, 2012	2011	2010	2009	2008
	(In thousands, except per share amounts)				
Total revenues	$13,712	$18,176	$28,525	$28,191	$40,895
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)	$665	$(8,892)
Net income (loss) per basic share outstanding	$0.49	$(0.62)	$(0.03)	$0.02	$(0.21)
Net income (loss) per diluted share outstanding	$0.49	$(0.62)	$(0.03)	$0.02	$(0.21)
Total assets	$92,574	$71,574	$90,706	$71,704	$85,295
Long-term debt	$390	$870	$232	$—	$—
Total equity attributable to Magellan Petroleum Corporation	$72,908	$52,528	$71,904	$53,513	$62,463
Non-controlling interest in subsidiaries	$—	$1,989	$1,914	$—	$—

ITEM 7: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis presents management's perspective of our business, financial condition, and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition, and outlook for the future and should be read in conjunction with Item 8: Financial Statements and Supplementary Data of this Form 10-K. In the following tables, the combination of Palm Valley and Mereenie represents our MPAL reporting segment. Amounts expressed in Australian currency are indicated as "AUD."

Forward looking statements are not guarantees of future performance, and our actual results may differ significantly from the results discussed in the forward looking statements. See "Forward Looking Statements" at the end of the section. Factors that might cause such differences include, but are not limited to, those discussed in the subsection entitled "Risk Factors" above, which are incorporated herein by reference. We assume no obligation to revise or update any forward looking statements for any reason, except as required by law.

OVERVIEW OF THE COMPANY

Magellan is an independent energy company engaged in the exploration, development, production, and sale of crude oil and natural gas. Our strategy is to enhance shareholder value by maximizing the value of our existing assets. We accomplish this through the exploration and development of our assets as outlined in Items 1 and 2: Business and Properties of this report.

SUMMARY RESULTS OF OPERATIONS FOR THE YEAR ENDED JUNE 30, 2012

For the year ended June 30, 2012, revenues totaled $13.7 million compared to $18.2 million in the prior year, a decrease of 25%. Operating income totaled $19.8 million compared to $28.2 million operating loss in the prior year. Net income totaled $26.5 million ($0.49/basic share), compared to a net loss of $32.4 million ($(0.62)/basic share) in the prior year. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) totaled negative $11.2 million, compared to negative $4.8 million in the prior year, a change of 135%. For further detail, please refer to the discussion below in this section under Comparison of Financial Results and Trends Between Fiscal 2012 and 2011.

During the quarter ended December 31, 2011, we have changed the presentation of our financial statements to conform them to industry-specific norms and to improve our reporting to shareholders and stakeholders. Specifically, we have modified the presentation of expenses in the consolidated statements of operations and the presentation of property and equipment in the consolidated balance sheets. As a result, certain reclassifications have been made to the prior period financial statements to align them with this revised presentation format. These reclassifications have no impact on previously reported results.

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HIGHLIGHTS OF OPERATIONAL ACTIVITIES

During the fiscal year ended June 30, 2012, management articulated a strategy to focus on proving up the value of its existing assets as the most economic way of increasing shareholder value. Towards that end, management has begun a number of initiatives to evaluate and determine the potential of its oil and gas properties. The below discussion should be read in conjunction with the discussion of Significant Developments in Fiscal Year 2012 under Part1, Items 1 and 2: Business and Properties above and the section covering Comparison of Results and Trends between Fiscal Years 2012 and 2011 below.

Poplar (Montana, United States)

Magellan 100% operated intervals. During the year ended June 30, 2012, Magellan sold 75 Mbbls of oil attributable to its net revenue interests in Poplar, compared to 68 Mbbls of oil sold during the same period in 2011. These results represent a 10% increase in average daily sales for the year from 186 boepd to 205 boepd. Approximately 5 Mbbls out of the 7 Mbbls increase were attributable to sales from the EPU 117 well, which produces out of the Amsden formation, a new pool discovery made in January 2012. This well currently produces at a stabilized production rate of 10 to 20 bopd. The remaining production increase of 2 Mbbls is primarily the result of workovers and Magellan's consolidation of its ownership in Poplar in September 2011.

Poplar was discovered in the 1950s by Murphy Oil Company, with much of the field's development occurring in the Charles formation between the 1950s and 1970s. Most of the field's current production is conventional production from the Charles formation generated by wells initially drilled in that era, and these wells require significant workovers and maintenance to maintain stable production.

To improve the production and profitability of Poplar, Magellan implemented a workover and exploration program during the past fiscal year aimed at increasing conventional production from its operated formations. The Company tested and evaluated several unexplored shallow formations which are prospective for hydrocarbons. The discovery of the Amsden formation was a result of this effort, and management is currently evaluating whether it is more economic to develop this formation through the recompletion of existing wells or through the drilling of new ones. In addition, Magellan assessed the effectiveness of certain production-enhancing technologies, such as stimoil treatments, acid stimulations, and water shut-off treatments, in certain intervals. These assessments are ongoing, and, if successful, Magellan will seek to deploy them on a full-field basis.

During the fiscal year, Magellan also focused heavily on evaluating the potential for a CO_2-EOR project in the Charles formation at Poplar. During the third and fourth fiscal quarters, the Company commissioned various laboratory analyses of oil samples taken from the Charles formation, including studies of minimum miscibility pressure, CO_2 solubility swelling, and viscosity reduction. Magellan received analysis results back between May and August 2012, all of which confirm the potential viability of CO_2-EOR at Poplar. In addition, Magellan has utilized the EPU 119 well, initially drilled in 2010, to conduct CO_2 injectivity tests into the Charles formation under actual reservoir conditions. Such tests have been completed, and the results will support the viability of a CO_2-EOR at Poplar. Magellan is now working diligently to implement a five-well CO_2-EOR pilot project to be conducted during the fiscal year ending June 30, 2013.

VAALCO 65% operated intervals. In September 2011, we farmed out part of our interest in the Bakken/Three Forks and deeper formations to VAALCO in return for their commitment to drill three exploration wells. This arrangement allows us to focus on the shallower formations while VAALCO tests the deeper formations, including the Bakken/Three Forks, Nisku, and Red River, on our collective behalf.

Australia

Palm Valley. The Palm Valley gas field, which is operated by MPAL, produced a gross average of approximately 1.2 MMcf/d of natural gas for sale for the year ended June 30, 2012. Gas sales volumes at Palm Valley decreased due to the termination of the PWC Contract during January 2012. Gas sales resumed in February 2012 under month to month arrangements with Santos and were continued with Santos under a long-term gas sales agreement in May 2012 following completion of the Santos SA. Under these arrangements, sale terms were equivalent to those included in the Santos Gas Contract. The Santos Gas Contract became effective upon Completion of the Santos SA on May 25, 2012. To date, gas volumes sold under both the arrangements were significantly lower than under the PWC Contract, although volumes are expected to increase by fiscal year 2015 to levels similar to, and at prices significantly higher than, those realized under the PWC Contract. The average price of gas, net of royalties and prior year royalty adjustments, at Palm Valley was AUD $3.01/Mcf for the year ended June 30, 2012, compared to AUD $2.28/Mcf for the prior year.

During the fiscal year, Magellan took steps to reduce costs and improve operational efficiency at Palm Valley, including reducing its field staff from ten to five employees, while maintaining a safe and efficient operation, conducted in accordance with good oil field practice.

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Mereenie. The Mereenie oil and gas field, which is operated by Santos, produced a gross average of approximately 473 bbls of oil and condensate per day for sale during the period from July 1, 2011, to May 25, 2012, when the Santos SA was completed, compared to 493 bbls during the prior year. The average price of oil at Mereenie, net of royalties and prior year royalty adjustments, was AUD $132.92/bbl for the year ended June 30, 2012, compared to AUD $99.67/bbl for the prior year. There were no natural gas sales at Mereenie during fiscal years 2012 and 2011. Magellan sold its interests in Mereenie to Santos as part of the Santos SA (see Note 2) effective May 25, 2012, and the results of operations for fiscal year 2012 reflect a revenue contribution from Mereenie through that date.

United Kingdom

Celtique Energie Operated Licenses. In the Weald Basin, Magellan and Celtique Energie each own a 50% working interest in four licenses (PEDL 231, 232, 234, and 243) covering a gross total of approximately 270,000 acres, all expiring on June 30, 2014, unless extended. Celtique Energie continues to gather data to assess the prospect for unconventional and conventional hydrocarbon deposits in these licenses. In September 2011, Celtique completed the acquisition of approximately 200 km of 2-D seismic data. This seismic acquisition fulfilled our current work commitment under the licenses. These four licenses remain subject to contingent "drill-or-drop" requirements. This seismic data revealed several prospects, and an exploratory drilling program is under development.

Northern Petroleum Operated Licenses. In the Weald Basin of Southern England, the Company participated (40% interest) in the Markwells Wood-1 exploration well, which was drilled in PEDL 126 in December 2010. On November 21, 2011, this well was completed for production testing to establish pressures and flow rates in the existing wellbore. Further stimulation of the well was performed during December 2011 and February 2012, and production testing continued through April 2012 to establish a stabilized oil production rate. The well was then suspended, and is now being assessed by Northern for further actions. As operator of the well, Northern Petroleum will continue to publish periodic updates on the well status. Limited quantities of oil volumes have been produced from the Markwells Wood-1 well.

In January 2012, the United Kingdom Department of Energy, in the 26th Licensing Round, announced it will award an exploration license (an offshore license) to the Isle of Wight Joint Venture, which is composed of Northern Petroleum (63%), Magellan (23%), Egdon Resources (7%), Montrose Industries (5%), and Oil & Gas Investments (2%). The license is an exploration license for two part blocks located offshore in the Wessex Basin and contains a potential Wytch Farm type play. Northern Petroleum is the operator. Commitments to the license consist of a contingent “drill-or-drop” well with a decision on drilling to be made before the end of Permit Year 2.

ACQUISITIONS AND DIVESTITURES

During the fiscal year, Magellan executed a series of corporate transactions aimed at streamlining our corporate structure, gaining control and operatorship of our core assets, and allowing management to execute its strategy of proving the value of its assets.

Santos Transactions

On May 25, 2012, Magellan completed the Santos SA which consolidated our ownership in the Palm Valley and Dingo. The transaction had an effective date of July 1, 2011, and resulted in net cash proceeds of $26.6 million, including adjustments of $1.1 million (reflecting activity between the effective date and closing date), in addition to a gain on sale of assets in the amount of $36.2 million. The impact of this transaction is reflected in the consolidated financial statements included in this report (see Note 2).

Lease Purchase and Sale and Participation Agreement with VAALCO.

On September 6, 2011, the Company entered into a Lease Purchase and Sale and Participation Agreement with VAALCO, pursuant to which VAALCO will receive, subject to certain obligations, an undivided 65% of the Company's working interests at Poplar in formations including and below the Bakken/Three Forks. In exchange, Magellan received $5.0 million in cash proceeds and will be carried for 100% of the capital expenditures on the first three wells VAALCO will drill at Poplar in the deeper formations, all of which wells are due to be spud before December 31, 2012. The Company also recognized a gain on sale of assets in the amount of $4.0 million (see Note 2).

Acquisition of Non-Controlling Interest in Nautilus Poplar LLC and Acquisition of Additional Working Interests.

On September 2, 2011, effective from September 1, 2011, the Company entered into a Purchase and Sale Agreement (the "Nautilus PSA") between the Company and the non-controlling interest owners of its subsidiary, NP, (the "Nautilus Sellers"). The Nautilus PSA provided for the Company's purchase of all membership interests in NP and working interests in the leases of Poplar from the Nautilus Sellers in return for (i) $4.0 million in cash, (ii) $2.0 million less certain adjustments in privately issued shares of Magellan's common stock, and (iii) the potential for future production payments, collectively, of up to $5.0

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million if certain increased average daily production milestones are achieved. The impact of this transaction is reflected in the consolidated financial statements included in this report (see Note 2).
The Company and the Nautilus Sellers entered into a Registration Rights Agreement ("RRA"), pursuant to which the Company granted to the Nautilus Sellers certain registration rights with respect to the shares ("Registrable Securities") owned by each Nautilus Seller and issued under the Nautilus PSA. On October 14, 2011, the Company filed a registration statement on Form S-3 with the U.S. Securities Exchange Commission to register for public resale of 1,182,742 shares of the Company's common stock acquired in the Nautilus Restructuring by the Nautilus Sellers (the "Registration Statement"). On November 18, 2011, the Registration Statement on Form S-3 became effective. The Company agreed to pay all expenses associated with the registration of the Registrable Securities except the fees and disbursements of counsel to the Nautilus Sellers. The Company has no continuing obligation related to the RRA.

OTHER ITEMS

U.S. Federal Tax Withholdings

During the third quarter of fiscal year 2012, the Company identified a potential liability of approximately $2.0 million related to the Company's failure to make the required U.S. Federal tax withholding in the course of its initial acquisition of NP. In October 2009, Magellan acquired 83.5% of the membership interests in NP (the "Poplar Acquisition"), from the two majority owners of NP, White Bear LLC ("White Bear") and YEP I, SICAV-FES ("YEP I"). Both of these entities are affiliated with Mr. Bogachev, a Director of Magellan and a foreign national. Due to the status of YEP I as foreign entity and the members of White Bear being foreign nationals, Magellan was required to make U.S. Federal tax withholdings from the payments to or for the benefit of White Bear and YEP I. Of the $2.0 million liability, $1.3 million was estimated to relate to the interest sold by White Bear, $0.6 million to the interest sold by YEP I, and $0.1 million to Magellan's interest on late payment of the U.S. Federal tax withholdings.
Upon the filing of U.S. income tax returns in relation to the Poplar Acquisition and payment of corresponding income taxes by White Bear and YEP I, Magellan is deemed to be relieved of its liability for the U.S. Federal tax withholdings as well as related penalties and interest except for Magellan's interest on late payment of the U.S. Federal tax withholdings. With regards to White Bear, Magellan has confirmed that as of the date of this filing, Mr. Bogachev has filed his U.S. income tax return and paid taxes due on the Poplar Acquisition, which were estimated at $0.3 million. Magellan has agreed to pay Mr. Bogachev $0.3 million in additional compensation. Had Mr. Bogachev not filed and paid his tax return, Magellan's liability in relation to its U.S. Federal tax withholdings requirements was estimated at $1.3 million as of June 30, 2012. With regards to YEP I, Magellan continues to seek from YEP I or, because YEP I is a now defunct entity, from its successor entities, the filing of its U.S. income tax return.
As of June 30, 2012, we have recorded a total liability of $1.0 million under accrued and other liabilities in the consolidated balance sheets related to this matter. That amount is comprised of the $0.3 million payment to Mr. Bogachev, $0.6 million in withholdings, penalties, and interest related to YEP I, and $0.1 million related to Magellan's interest on late payment of the U.S. Federal tax withholdings. The effect on the consolidated statements of operations for the year ended June 30, 2012, is an expense of $0.9 million recorded under general and administrative expense and an interest expense of $0.1 million (see Note 11).
Based upon an evaluation of all relevant quantitative and qualitative factors, and after considering SEC Staff Accounting Bulletins Nos. 99 and 108, management believes that any amounts attributable to the years ending June 30, 2010, and 2011, and the impact of correcting such amounts in the year ending June 20, 2012, is not material to any of the Company's consolidated financial statements presented herein.

CONSOLIDATED LIQUIDITY AND CAPITAL RESOURCES

Historically, we have funded our activities from cash from operations and our existing cash balance. The Company has limited capital expenditure for which we are obligated pertaining to its leases and licenses, which allow for significant flexibility in the use of its capital resources. Based on its existing cash position including, the additional proceeds resulting from the completion of the Santos SA, and the various alternative sources of funds generally available to the Company, the Company believes it has sufficient financial resources to fund its ongoing operations and to finance projects that will further establish the full value of its assets.

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Uses of Funds

Capital Expenditures Plans. At Poplar, the Company does not face significant mandatory capital expenditure requirements to maintain its acreage position. Substantially all of the leases are held by production and contain producing wells with reserves adequate to sustain multi-year production. Approximately 80% of the acreage has been unitized as a Federal Exploratory Unit which is held by production from any one well. Currently, Poplar contains 39 producing wells. In the shallow intervals, which are 100% owned and operated by the Company, discretionary capital expenditure plans over the next two years will be determined by the results of ongoing engineering and technical analysis. In fiscal year 2013, the Company intends to evaluate the potential of CO_2-EOR in the Charles formation at Poplar by drilling a five-well pilot, including one CO_2 injector well and four producing wells. Magellan expects to incur up to $10.0 million in capital costs on these wells. Timing of the drilling of these wells will depend on the permitting process and drilling rig availability. The four producing wells are designed to yield conventional oil production from the Charles formation in addition to enhanced production as a result of the CO_2-EOR. As such, these four wells will constitute a portion of the wells to be drilled in the projections of our proved undeveloped reserves.

In the deeper intervals, which are operated by VAALCO and in which the Company has a 35% working interest, capital expenditures will be determined by the results of the three test wells which VAALCO is required to have spud by the end of calendar year 2012, and for which VAALCO will bear 100% of the capital expenditures. If these test wells are deemed successful, the Company plans to fund its 35% share of the cost of the future drilling program in the deeper formations of Poplar.

At Palm Valley, the Company's interest in the field is governed by Petroleum Lease No. 3, which expires in November 2024 (and is subject to automatic renewal for another 21 years). The Company is not obligated to undertake significant mandatory capital expenditures in order to maintain its position in the lease. The Company's discretionary capital expenditure plans are primarily focused on maintaining gas production from the existing facilities to meet the Santos Gas Contract demand while maintaining a safe and efficient operation, conducted in accordance with good oil field practice.

At Dingo, the Company's interest in the field is governed by Retention License No. 2, which expires in February 2014 (and is subject to renewal for a further 5 years). No mandatory capital expenditure is required until new gas sales contracts are secured. Dingo contains two suspended wells which are capable of production. The Company is currently evaluating a number of options for the future development of this field and is in the process of identifying potential new gas customers.

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in the NT/P82 Exploration Permit. Under the terms of the permit, which is due to expire in May 2016, the Company committed to a minimum 46 square mile 3-D seismic survey in 2012. Magellan currently plans to shoot 2-D and 3-D seismic over the permit in the second quarter of fiscal year 2013 at an estimated cost of less than $5.0 million, including the costs of processing and analyzing the seismic. Timing of the shoot is subject to finalization of our environment plans with local authorities and to the contract with the vessel and service provider.

In the United Kingdom, the Company's interests are governed by various Petroleum Exploration and Development Licenses. The majority of these licenses expire in 2014, and all are subject to "drill-or-drop" obligations (for further detail, see Operations under Part 1, Items 1 and 2: Business and Properties). The Company has minimal remaining capital expenditure obligations with respect to its interest in the Markwells Wood-1 well operated by Northern Petroleum.

Contractual Obligations. The following table summarizes our obligations and commitments as of June 30, 2012, to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Purchase obligations (1)	$5,385	$5,385	$—	$—	$—
Asset retirement obligations	7,784	329	1,321	—	6,134
Contingent consideration payable (2)	4,072	—	4,072	—	—

Operating leases [3]	1,152	97	424	541	90
Long term debt, including interest [4]	918	517	401	—	—
Total	$19,311	$6,328	$6,218	$541	$6,224

[1] Purchase obligations are attributable to certain exploration and capital expenditures related to MPAL.
[2] Assumptions for the timing of these payments are based on our reserve report and planned drilling activity.
[3] Operating lease obligations are shown net of guaranteed sublease income.
[4] Long term debt in this table includes the current portion and accrued interest of $48 thousand for the 6.25% note payable (see Note 3).

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Sources of Funds

Cash and Cash Equivalents. On a consolidated basis, the Company had approximately $41.2 million of cash and cash equivalents at June 30, 2012, compared to $20.4 million as of June 30, 2011.

The Company considers cash equivalents to be short term, highly liquid investments that are both readily convertible to known amounts of cash and so near their maturity that they present insignificant risk of changes in value because of changes in interest rates. As of June 30, 2012, $39.7 million of the Company’s consolidated cash and cash equivalents were deposited in accounts held by MPAL, of which $38.6 million was held in several Australian banks in time deposit accounts that have terms of 90 days or less. As of September 24, 2012, the company has repatriated $20.0 million of these Australian held funds to the U.S. The Company does not anticipate that U.S. Federal Income Tax will be owed on this amount. The intended use for the repatriated monies is the funding of Magellan's U.S. based operations, including part of its drilling activity at Poplar.

Due to the international nature of its operations, the Company is exposed to certain legal and tax constraints in matching the capital needs of its assets and its cash resources. To the extent that the Company repatriates cash amounts from MPAL to the U.S., the Company is potentially liable for incremental U.S. Federal and State Income Tax, which may be reduced by the U.S. Federal and State net operating loss and foreign tax credit carry forwards available to the Company at that time.

Marketable Securities. The Company may from time to time invest in marketable securities consisting of investments in U.S. Treasury Bills with maturities usually not exceeding six months. As of June 30, 2012, and June 30, 2011, respectively, the Company had no marketable securities.

Existing Credit Facilities. The Company's outstanding borrowings are summarized below for the years ended:

	June 30,	
	2012	2011
	(In thousands)	
Outstanding borrowings:		
Term loan	$870	$1,422
Line of credit	50	1
Total	$920	$1,423

The Company, through its wholly owned subsidiary NP, maintains its only credit facility with Jonah Bank of Wyoming. As of June 30, 2012, the Company’s borrowing capacity under these facilities totaled $2.3 million, consisting of a $1.3 million term loan and a $1.0 million line of credit. Of the $1.3 million term loan, $0.9 million was drawn as of June 30, 2012. Of the $1.0 million line of credit, $50 thousand was drawn, $25 thousand secured business credit cards used by NP, $25 thousand secured a line of credit in favor of the Bureau of Land Management, and $900 thousand remained available to borrow. As of June 30, 2012, NP was in compliance with its financial covenants as set forth in the term loan agreement. The credit facilities are collateralized by a first mortgage and an assignment of production from Poplar and are guaranteed by the Company up to $6.0 million but not to exceed the amount of the principal owed, which was $920 thousand as of June 30, 2012.

Other Sources of Financing. In addition to its cash and existing credit facilities, the Company has various alternatives to fund the development of its assets. These alternatives could potentially include entering into a corporate credit facility, a reserve-based loan facility, a farmout of a portion of the development program of some of the Company's assets, and an issuance of new shares to equity investors and monetization of non-core assets.

Cash Flows

The following table presents the Company's cash flow information for the years ended:

	June 30,	
	2012	2011
	(In thousands)	
Cash (used in) provided by:		
Operating activities	$(10,441)	$(4,495)
Investing activities	35,629	(13,481)
Financing activities	(3,928)	561

Effect of exchange rate changes on cash and cash equivalents	(462)	4,240
Net increase (decrease) in cash and cash equivalents	$20,798	$(13,175)

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Cash used in operating activities during the year ended June 30, 2012, was $10.4 million, compared to cash used of $4.5 million in 2011. The increase in cash used in operating activities primarily resulted from a combination of a decrease in revenues of $4.5 million over the prior year and increased operational spending related to exploration and lease operating expenses of $3.7 million and $3.4 million, respectively. These factors were partially offset by a reduction in general and administrative costs (excluding stock based compensation and foreign transaction loss) of $1.7 million.

Cash provided by investing activities during the year ended June 30, 2012, was $35.6 million, compared to cash used of $13.5 million in 2011. The increase in cash provided by investing activities resulted from $5.0 million in proceeds from the VAALCO PSA (see Note 2), the refund of a $10.9 million deposit related to the Evans Shoal Asset Sales Deed, and $29.6 million in cash proceeds from the Santos SA (see Note 2), offset by $0.8 million spent on the purchase of non-controlling interests in Poplar and $9.6 million in expenditures on the development of our assets. Of the $9.6 million, $2.4 million related to the recompletion of four wells and the repair of one of our salt water disposal wells at Poplar, $1.6 million related to exploration activities at Poplar, primarily for the EPU 117 well, $1.2 million related to the Markwells Wood-1 well in the United Kingdom, and $3.4 million represented the acquisition of the remaining interest in the Palm Valley and Dingo gas fields.

Cash used in financing activities during the year ended June 30, 2012, was $3.9 million, compared to cash provided of $0.6 million in 2011. The increase in cash used in financing activities related to the $3.5 million purchase of the non-controlling interest in Poplar (see Note 2) and the repayment of the Company's long term debt of $0.5 million.

During the year ended June 30, 2012, the effect of changes in foreign currency exchange rates negatively impacted the translation of our AUD denominated cash and cash equivalent balances into U.S. dollars and resulted in a decrease of $0.5 million in cash and cash equivalents, compared to an increase of $4.2 million in 2011.

The Company also expects the impact of non-cash foreign transaction gains and losses in the consolidated statements of cash flows to be reduced in future periods. The source of the impact was primarily generated by MPAL's cash balances in U.S. dollar denominated accounts held in relation to the Evans Shoal Asset Sales Deed. Cash balances held in these accounts have now been reduced to immaterial amounts.

COMPARISON OF FINANCIAL RESULTS AND TRENDS BETWEEN FISCAL 2012 AND 2011

Oil and Gas Sales Volumes

The following table presents oil and gas sales volumes for the years ended:

	June 30, 2012	2011	Difference	Percent change
Net sales by field:				
Poplar (Mbbls)	75	68	7	10 %
Palm Valley gas (MMcf)	434	712	(278)	(39)%
Mereenie oil (Mbbls)	45	55	(10)	(18)%
Total Australia sales (Mboe)	119	174	(55)	(32)%
Net sales by product:				
Oil (Mbbls)	122	123	(1)	(1)%
Gas (MMcf)	434	712	(278)	(39)%
Consolidated sales (Mboe)	194	242	(48)	(20)%
Consolidated sales (boepd)	531	662	(131)	(20)%

Sales volumes for the year ended June 30, 2012, totaled 194 Mboe (531 boepd), compared to 242 Mboe (662 boepd) sold in the prior year period, a decrease of 20%.The primary driver of this decline is the end of the PWC Contract of Palm Valley which was partially offset by increased production at Poplar. Sales volumes by product for the year ended June 30, 2012, were 63% oil and 37% gas, compared to 51% oil and 49% gas in the prior year, with the change due to the reduced contribution of gas sales from Palm Valley. At Poplar, volumes were positively impacted by the

EPU 117 well, which was completed in January 2012 in the Amsden formation, a new pool discovery at Poplar, by Magellan's consolidation of its interests in Poplar in September 2011 (see Note 2), and by the results of the continuing workover program. Gas sales volumes at Palm Valley decreased due to the termination of the 25 year PWC Contract during January 2012. Gas sales resumed in February 2012 under a month to month arrangement with Santos and were continued under a long-term gas sales agreement in May 2012 following

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completion of the Santos SA. The month to month arrangement was entered into with Santos while we were awaiting the Completion of the Santos SA and represented sales to Santos that were subsequently sold on by Santos to third-party customers. Since February 2012, gas volumes sold under these arrangements were significantly lower relative to the prior year period, although volumes are expected to increase over time and reach approximately 1.5 Bcf per year by fiscal 2015. At Mereenie, oil sales volumes decreased primarily due to Magellan's sale of its interests in the field in May 2012.

Oil and Gas Prices

The following table presents the average realized oil and gas prices for the years ended:

	June 30, 2012	2011	Difference	Percent change
Average realized price [(1)]:				
Poplar (USD/bbl)	$82.66	$77.96	$4.70	6 %
Palm Valley (AUD/Mcf)	$3.01	$2.28	$0.73	32 %
Mereenie oil (AUD/bbl)	$132.92	$99.67	$33.25	33 %
Consolidated (USD/boe)	$70.95	$56.27	$14.68	26 %

[(1)] Prices per bbl or per Mcf are reported net of royalties. Current period prices may be influenced by prior period royalty adjustments arising from annual royalty audits.

The average realized price for the year ended June 30, 2012, was $70.95/boe compared to $56.27/boe in the prior year period, an increase of 26%. This increase in price is primarily the result of an increase in the contribution of oil sales to total sales during the year ended June 30, 2012, as well as increased oil prices in the United States and Australia relative to the prior year. At present, the Company does not engage in any oil and gas hedging activities. Relative to the prior year period, the average realized price from oil sales at Poplar increased by 6% as a result of an increase in its benchmark pricing (WTI). The average realized gas price from Palm Valley increased by 32%, which reflects the higher gas prices realized under both monthly sales arrangements with Santos in place from February to May 2012 and the long-term gas sales contract in place with Santos from May 2012 compared to prices that were realized under the PWC Contract, which ended in January 2012. The gas price currently realized at Palm Valley is approximately AUD $4.7/Mcf, compared to AUD $2.3/Mcf under the terms of the prior long term gas sales contract. The average realized oil price from Mereenie increased by 33% as a result of an increase in its benchmark pricing (Tapis).

Revenues

The following table presents revenues for the years ended:

	June 30, 2012	2011	Difference	Percent change
	(In thousands)			
Net revenue by source:				
Poplar (USD)	$6,172	$5,383	$789	15 %
Palm Valley (USD)	1,347	1,778	(431)	(24)%
Mereenie (USD)	6,232	6,432	(200)	(3)%
Other (USD)	(39)	4,583	(4,622)	(101)%
Total (USD)	$13,712	$18,176	$(4,464)	(25)%
Palm Valley (AUD)	$1,305	$1,797	$(492)	(27)%
Mereenie (AUD)	$6,037	$6,502	$(465)	(7)%
Net revenues by type (USD):				
Oil	$12,405	$11,815	$590	5 %
Gas	1,353	1,796	(443)	(25)%
Other	(46)	4,565	(4,611)	(101)%
Total	$13,712	$18,176	$(4,464)	(25)%

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Revenues for the year ended June 30, 2012, totaled $13.7 million, compared to $18.2 million in the prior year period, a decrease of 25%. The $4.5 million decrease in revenue was driven by the end of the Amadeus Gas Trust revenue stream on June 16, 2011, which contributed $4.5 million to the Company's revenues in the prior period. The decreases in revenues at Palm Valley and Mereenie was offset by an increase in revenues from Poplar.

Operating and Other Expenses

The following table presents selected operating expenses for the years ended:

	June 30, 2012 (In thousands)	2011	Difference	Percent change
Selected operating expenses (USD):				
Lease operating	$12,897	$9,247	$3,650	39 %
Depletion, depreciation, amortization, and accretion	$1,744	$2,890	$(1,146)	(40)%
Exploration	$6,291	$2,854	$3,437	120 %
General and administrative	$13,091	$16,307	$(3,216)	(20)%
Selected operating expenses (USD/boe):				
Lease operating	$66	$38	$28	74 %
Depletion, depreciation, amortization, and accretion	$9	$12	$(3)	(25)%
Exploration	$32	$12	$20	167 %
General and administrative	$67	$67	$—	— %

Lease Operating Expenses. Lease operating expenses increased by $3.6 million to $12.9 million, or $66/boe, during the year ended June 30, 2012. Lease operating expenses at Poplar increased by approximately $2.2 million, of which $0.5 million related to increased workover activities and increased testing of production-enhancing technologies on certain wells. An additional $0.7 million was incurred during the current year compared to the prior year related to increased production taxes. Lease operating expenses in Australia increased by approximately $1.4 million, primarily as the result of higher costs at Palm Valley related to severance costs, following a reduction of field personnel and increased lease operating expenses at Mereenie. Mereenie contributed approximately $6.0 million to lease operating expenses incurred in the current year.

Depletion, Depreciation, Amortization, and Accretion. The following table presents depletion, depreciation, amortization, and accretion for the years ended:

	June 30, 2012 (In thousands)	2011	Difference	Percent change
Depreciation and amortization	$433	$441	$(8)	(2)%
Depletion	743	1,885	(1,142)	(61)%
ARO accretion	568	564	4	1 %
Total	$1,744	$2,890	$(1,146)	(40)%

Depletion, depreciation, amortization, and accretion expenses decreased by $1.1 million to $1.7 million, or $9/boe, during the year ended June 30, 2012. Depletion decreased in fiscal year 2012 relative to the same prior year period due to MPAL's Australian oil and gas assets being fully depleted as of September 30, 2010.

Exploration Expenses. Exploration expenses increased by $3.4 million to $6.3 million, or $32/boe, during the year ended June 30, 2012. The $3.4 million increase is the result of an increase of $1.0 million at NP and a $2.4 million increase at MPAL. Of the $6.3 million of exploration expenses incurred during the current period, $2.9 million related to non-cash exploration write offs, which included $1.2 million related to the EPU 119 well at Poplar and $1.5 million related to the Markwells Wood-1 well in the United Kingdom. The remaining $3.4 million were incurred towards general and seismic exploration costs, including $2.7 million incurred in the Weald Basin in the United Kingdom, $0.3 million related to analysis of the planned CO_2-EOR project at Poplar, and $0.4 million related to exploration costs incurred at Mereenie.

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General and Administrative Expenses. The following table presents general and administrative expenses for the years ended:

	June 30, 2012	2011	Difference	Percent change
	(In thousands)			
General and administrative (excluding stock based compensation and foreign transaction loss)	$12,006	$13,686	$(1,680)	(12)%
Stock based compensation	1,560	1,670	(110)	(7)%
Foreign transaction (gain) loss	(475)	951	(1,426)	(150)%
Total	$13,091	$16,307	$(3,216)	(20)%

General and administrative expenses decreased by $3.2 million to $13.1 million, during the year ended June 30, 2012. General and administrative expenses, excluding stock based compensation and foreign transaction losses and gains, amounted to $12.0 million, a decrease of $1.7 million. This decrease resulted from a significant reduction in the use of third party professional services and a number of cost saving initiatives which were undertaken during the year but were partially offset by their respective implementation costs. In fiscal year 2012 relative to the prior year period, accounting, legal, and consulting services decreased by $3.0 million, salary expenditures increased by $0.7 million in relation to the development and expansion of human resources in the Company, and bonuses paid to employees increased by $0.3 million. Additionally we recorded a $0.9 million expense, which represents the Company's maximum liability with respect to a withholding tax issue that arose in connection with the Company's acquisition of Nautilus Poplar LLC in October 2009 (see Note 11).

COMPARISON OF FINANCIAL RESULTS AND TRENDS BETWEEN FISCAL 2011 AND 2010

Oil and Gas Sales Volumes

The following table presents oil and gas sales volumes for the years ended:

	June 30, 2011	2010	Difference	Percent change
Net sales by field:				
Poplar (Mbbls)	68	42	26	62%
Palm Valley gas (MMcf)	712	1,166	(454)	(39)%
Mereenie gas (MMcf)	—	2,264	(2,264)	(100)%
Mereenie oil (Mbbls)	55	68	(13)	(19)%
Other MPAL oil sales (Mbbls)	—	29	(29)	(100)%
Total Australia sales (Mboe)	174	669	(495)	(74)%
Net sales by product:				
Oil (Mbbls)	123	139	(16)	(12)%
Gas (MMcf)	712	3,430	(2,718)	(79)%
Consolidated sales (Mboe)	242	711	(469)	(66)%
Consolidated sales (boepd)	662	1,948	(1,286)	(66)%

Sales volumes for the year ended June 30, 2011, totaled 242 Mboe (662 boepd), compared to 711 Mboe (1,948 boepd) sold in the prior year, a decrease of 66%. Sales volumes by product for the year ended June 30, 2011, were 51% oil and 49% gas, compared to 20% oil and 80% gas in the prior year. At Poplar, volumes were positively impacted primarily by Magellan's purchases of additional working interests in the leases of Poplar. In Australia, oil volumes decreased primarily due to the sale of Cooper Basin and Nockatunga Assets in fiscal year 2010, while gas volumes were negatively impacted by the end of the Mereenie MSA4 gas sales contract in February 2010.

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Oil and Gas Prices

The following table presents the average realized oil and gas prices for the years ended:

	June 30, 2011	2010	Difference	Percent change
Average realized price [1]:				
Poplar (USD/bbl)	$77.96	$67.88	$10.08	15%
Palm Valley (AUD/Mcf)	$2.28	$2.25	$0.03	1%
Mereenie gas (AUD/Mcf)	$—	$6.53	$(6.53)	(100)%
Mereenie oil (AUD/bbl)	$99.67	$85.50	$14.17	17%
Consolidated (USD/boe)	$56.27	$33.02	$23.25	70%

[1] Prices per bbl or per Mcf are reported net of royalties. Current period prices may be influenced by prior period royalty adjustments arising from annual royalty audits.

The average realized price for the year ended June 30, 2011, was $56.27/boe compared to $33.02/boe in the prior year period, an increase of 70%. This increase in price is primarily the result of increased oil prices in the United States and Australia, as well as an increase in the contribution of oil sales to total sales during the year ended June 30, 2011, relative to the prior year. At present, the Company does not engage in any oil and gas hedging activities. Relative to the prior year period, the average realized price from oil sales at Poplar increased by 15% as a result of increased benchmark pricing (WTI). The average realized gas price from Palm Valley increased by 1%, in line with the terms of its gas sales contract with the PWC Contract. The average realized oil price from Mereenie increased by 17% as a result of an increase in its benchmark pricing (Tapis).

Revenues

The following table presents revenues for the years ended:

	June 30, 2011 (In thousands)	2010	Difference	Percent change
Net revenue by source:				
Poplar (USD)	$5,383	$2,594	$2,789	108%
Palm Valley (USD)	1,778	2,059	(281)	(14)%
Mereenie (USD)	6,432	18,826	(12,394)	(66)%
Other (USD)	4,583	5,046	(463)	(9)%
Total (USD)	$18,176	$28,525	$(10,349)	(36)%
Palm Valley (AUD)	$1,797	$2,332	$(535)	(23)%
Mereenie gas (AUD)	$—	$13,094	$(13,094)	(100)%
Mereenie oil (AUD)	$6,502	$8,236	$(1,734)	(21)%
Net revenues by type (USD):				
Oil	$11,815	$9,887	$1,928	20%
Gas	1,796	13,616	(11,820)	(87)%
Other	4,565	5,022	(457)	(9)%
Total	$18,176	$28,525	$(10,349)	(36)%

Revenues for the year ended June 30, 2011, totaled $18.2 million, compared to $28.5 million in the prior year period, a decrease of 36%. The $10.3 million decrease in revenue was primarily due to the end of the Mereenie MSA4 contract in February 2010, which was partially offset by an increase in revenues at Poplar.

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Operating and Other Expenses

The following table presents selected operating expenses for the years ended:

	June 30, 2011	2010	Difference	Percent change
	(In thousands)			
Selected operating expenses (USD):				
Lease operating	$9,247	$10,116	$(869)	(9)%
Depletion, depreciation, amortization, and accretion	$2,890	$5,428	$(2,538)	(47)%
Exploration	$2,854	$1,273	$1,581	124 %
General and administrative	$16,307	$14,023	$2,284	16 %
Selected operating expenses (USD/boe):				
Lease operating	$38	$14	$24	171 %
Depletion, depreciation, amortization, and accretion	$12	$8	$4	50 %
Exploration	$12	$2	$10	500 %
General and administrative	$67	$20	$47	235 %

Lease Operating Expenses. Lease operating expenses decreased $0.9 million to $9.2 million, or $38/boe, during the year ended June 30, 2011. Lease operating expenses decreased due to the result of cost reduction efforts at Mereenie and Palm Valley, which included a new transportation contract at Mereenie, the elimination of prior year pipeline repair costs at Mereenie, and the elimination of production repair costs related to the Cooper Basin Assets sold in fiscal year 2010. These cost reductions were offset by increases in production costs related to Magellan's increased ownership of working interests in the leases of Poplar.

Depletion, Depreciation, Amortization, and Accretion. The following table presents depletion, depreciation, amortization, and accretion for the years ended:

	June 30, 2011	2010	Difference	Percent change
	(In thousands)			
Depreciation and amortization	$441	$436	$5	1 %
Depletion	1,885	4,244	(2,359)	(56)%
ARO accretion	564	748	(184)	(25)%
Total	$2,890	$5,428	$(2,538)	(47)%

Depletion, depreciation, amortization, and accretion expenses decreased $2.5 million to $2.9 million, or $12/boe, during the year ended June 30, 2011. Depletion decreased in fiscal 2011 relative to the prior year period due MPAL's SEC defined reserves for oil were non-economic as of June 30, 2010.

Exploration Expenses. Exploration expenses increased by $1.6 million to $2.9 million, or $12/boe, during the year ended June 30, 2011. The $1.6 million increase is the result of an increase of $0.5 million at NP and $1.1 million increase at MPAL. Of the $2.9 million, $0.4 million related to Poplar, $0.4 million related to the Bonaparte and Maryborough Basins, $0.5 million related to Mereenie, and $1.6 million related to general exploration in the Weald Basin.

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General and Administrative Expenses. The following table presents general and administrative expenses for the years ended:

	June 30, 2011 (In thousands)	2010	Difference	Percent change
General and administrative (excluding stock based compensation and foreign transaction loss)	$13,686	$11,041	$2,645	24 %
Stock based compensation	1,670	2,305	(635)	(28)%
Foreign transaction loss	951	677	274	40 %
Total	$16,307	$14,023	$2,284	16 %

General and administrative expenses increased $2.3 million to $16.3 million, or $67/boe, during the year ended June 30, 2011. General and administrative expenses, excluding stock based compensation and foreign transaction losses and gains, increased by $2.6 million to $13.7 million, or $57/boe. This increase resulted from $2.0 million in increased consulting costs and $0.5 million in increased legal costs related to the Evans Shoal transaction and an increase in severance payments of $0.1 million due to the departure of a senior executive during the year ended June 30, 2011.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not use off-balance sheet arrangements, such as securitization of receivables, with any unconsolidated entities or other parties.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates, and judgments made by management in Note 1 to our consolidated financial statements. We have outlined below certain more significant estimates and assumptions used in preparation of our consolidated financial statements.

Oil and Gas Properties

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense and included within the consolidated statement of cash flows and reported as capital expenditures under investing activities. The costs of development wells are capitalized whether those wells are successful or unsuccessful. The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which classification will ultimately determine the proper accounting treatment of the costs incurred. Exploratory drilling costs are initially capitalized pending determination of proved reserves but are charged to expense if no proved reserves are found.

Oil and Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment. As a result, adjustments to depletion and impairment are made concurrently with changes to reserves estimates. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and FASB. Our independent third party engineering firms adhere to the same guidelines when auditing our reserve reports. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the reserves estimates. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. As a result, material revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserves estimates represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our

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financial statements. As such, reserves estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Depreciation, Depletion, and Amortization. The provision for depletion of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method and is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions regarding future development and abandonment costs as well as our level of capital spending. If the estimates of total proved or proved developed reserves decline, the rate at which we record depreciation, depletion and amortization ("DD&A") expense increases, which in turn, increases DD&A expense. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. Oil and gas properties are assessed annually, or more frequently as economic events dictate, for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its fair value. We estimate the fair value using expected future cash flows of our oil and gas properties and compare these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the cost of the property is written down to fair value, which is determined using net discounted future cash flows from the producing property. Different pricing assumptions (see Note 13) or discount rates could result in a different calculated impairment.

Asset Retirement Obligation. Our asset retirement obligations (“AROs”) consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas properties. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions, and judgments regarding such factors as amounts, future advances in technology, timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact operating results as accretion expense. The related capitalized cost, net of estimated salvage values, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Revenue Recognition

We record revenues from the sale of oil and gas in the month in which the delivery to the purchaser occurred and title transferred. We receive payment one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, any differences have been insignificant.

Stock Based Compensation

We recognize compensation expense for all share-based payment awards made to employees and directors. Stock based compensation expense is measured at the grant date based on the fair value of the award. Judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. The Black-Scholes-Merton pricing model uses assumptions regarding expected volatility of our common stock, the risk-free interest rates, expected term of the awards, and other valuation inputs, which are subject to change. Any such changes could result in different valuations and thus impact the amount of stock based compensation expense recognized.

Costs related to time based stock options are recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. Performance based options are recognized when the achievement of the performance conditions is considered probable. Management re-assesses whether satisfaction of performance conditions are probable at the end of each reporting period. As of June 30, 2012, management believes the achievement of the performance conditions related to the performance based stock options is probable.

We recorded non-cash stock based compensation expense for the years ended June 30, 2012, 2011, and 2010, of $1.6 million, $1.7 million, and $2.3 million, respectively.

Income Taxes and Uncertain Tax Positions

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a more likely than not recognition threshold that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Previously recognized uncertain tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met. We currently do not have any uncertain tax positions recorded as of June 30, 2012.

Foreign Currencies and Foreign Currency Adjustment of Intercompany Loans

When intercompany foreign currency transactions between entities included in the consolidated financial statements are of a long-term investment nature (i.e., those for which settlement is not planned or anticipated in the foreseeable future) foreign currency translation adjustments resulting from those transactions are included in stockholders' equity as accumulated other comprehensive income (loss). However, when intercompany transactions are deemed to be of a short term nature, translation adjustments are required to be included in the consolidated statement of operations.

As a result of the Company's repatriation of Australian held funds to the U.S. during the first quarter of fiscal year 2013, we will need to assess whether all investments and intercompany transactions would continue to be considered long-term in nature. In the event certain transactions and/or investments are no longer considered long-term in nature, any subsequent foreign currency translation adjustments associated with such items would be required to be reflected in the Company's future statements of operations. Accordingly, if foreign currency translation adjustments are required to be reported in our future statements of operations, exchange rate volatility could have a significant effect on future period results of operations.

During fiscal 2012, all foreign currency translation adjustments were recorded as a separate component of stockholders' equity as accumulated other comprehensive income (loss).

Accounting for Business Combinations

The Company continues to pursue acquisitions as opportunities arise in order to grow our business. We have accounted for all of our business combinations to date in accordance with guidelines established by FASB, using the acquisition method of accounting, which involves the use of significant judgment.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market based weighted average cost of capital rate, adjusted for risk, determined to be appropriate at the time of the acquisition.

The fair value of contingent consideration is calculated using production projections and the estimated timing of production payouts. The Company also utilized a discount factor which is consistent with the rate used in valuing its asset retirement obligation and reflects the Company’s credit adjusted incremental borrowing rate.

Authoritative Accounting Matters

See "Recently Issued Accounting Standards" under Note 1 for additional information on the recent adoption of new authoritative accounting guidance in Part II, Item 8: Financial Statements and Supplementary Data of this Form 10-K.

FORWARD LOOKING STATEMENTS

Our disclosure and analysis in this report contains forward looking information that involves risks and uncertainties. Our forward looking statements express our current expectations or forecasts of possible future results or events, including projections of future performance, statements of management’s plans and objectives, future contracts, and forecasts of trends and other matters. Forward looking statements speak only as of the date of this report, and we undertake no obligation to update or revise such statements to reflect new circumstances or unanticipated events as they occur. You can identify these statements by the fact that they do not relate strictly to historic or current facts and often use words such as "anticipate," "estimate," "expect," "believe," "will likely result," "outlook," "project," and other words and expressions of similar meaning. No assurance can be given that the results expressed or implied in any forward looking statements will be achieved, and actual results could be affected by one or more factors, which

could cause them to differ materially. For these statements, we claim the protection of the safe harbor for forward looking statements contained in the Private Securities Litigation Reform Act of 1995.
Among these risks and uncertainties are: (i) whether the Company can successfully achieve cost savings while delivering revenue growth; (ii) whether the workovers, recompletions, and other drilling at Poplar will result in increased production and

cash generation and/or will otherwise successfully assist in the development of Poplar; and (iii) the production levels from the properties in which the Company, through its subsidiaries, have interests, the recoverable reserves at those properties, and the prices that will ultimately be applied to the sale of such reserves and other risks described under the caption "Risk Factors" in this Annual Report on Form 10-K. The Company assumes no obligation to update any forward looking statements contained in this report, whether as a result of new information, future events, or otherwise, except as required by securities laws.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company's exposure to market risk relates to fluctuations in foreign currency and world prices for crude oil, as well as market risk related to investment in marketable securities. The exchange rates between the Australian dollar and the U.S. dollar, as well as the exchange rates between the U.S. dollar and the British pound, have changed in recent periods and may fluctuate substantially in the future. Any appreciation of the U.S. dollar against the Australian dollar is likely to have a negative impact on our revenue, operating income, and net income. Because of our U.K. development program, a portion of our expenses, including exploration costs and capital and operating expenditures will continue to be denominated in British pound. Accordingly, any material appreciation of the British pound against the Australian and U.S. dollars could have a negative impact on our business, operating results, and financial condition.

For the twelve months ended June 30, 2012, oil sales represented approximately 63% of total oil and gas revenues. Based on fiscal year 2012 sales volume and revenues, a 10% change in oil price would increase or decrease oil revenues by $1.2 million. Gas sales, which represented approximately 37% of total oil and gas revenues in the current twelve months, are derived primarily from the Palm Valley gas field in the Northern Territory of Australia and the gas prices are set according to long term contracts that are subject to changes in the Australian Consumer Price Index for the twelve months ended June 30, 2012.

At June 30, 2012, the carrying value of cash and cash equivalents was approximately $41.2 million, which approximates the fair value.

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ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
Magellan Petroleum Corporation
Denver, Colorado

We have audited the consolidated balance sheet of Magellan Petroleum Corporation and subsidiaries (the "Company") as of June 30, 2012, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the year ended June 30, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of the Company as of June 30, 2011 and for the years ended June 30, 2011 and 2010, before the effects of retrospective adjustments applied for (1) for the adoption of Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, as amended ("ASU 2011-5") discussed in Note 1 to the consolidated financial statements, (2) to the disclosures for a change in the composition of reportable segments discussed in Notes 1 and 9 to the consolidated financial statements, and (3) for reclassifications to certain financial statement captions to conform the presentation of the consolidated financial statements to industry-specific norms discussed in Notes 1 and 16 to the consolidated financial statements, were audited by other auditors whose report, dated September 20, 2011, expressed an unqualified opinion on those consolidated financial statements.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements, present fairly, in all material respects, the financial position of Magellan Petroleum Corporation and subsidiaries as of June 30, 2012, and the results of their operations and their cash flows for the year ended June 30, 2012, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 16 to the consolidated financial statements the Company made reclassifications to certain 2011 and 2010 financial statement captions to conform the presentation with the 2012 consolidated financial statement presentation which management believes better aligns with industry-specific norms.

Also as discussed in Note 1, the Company early adopted Accounting Standards No. 2011-5, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, as amended ("ASU 2011-5")

We have also audited the adjustments to the 2011 and 2010 consolidated financial statements to retrospectively apply the (1) adoption of Accounting Standards No. 2011-5, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, as amended ("ASU 2011-5") discussed in Note 1 to the consolidated financial statements, (2) to the disclosures for a change in the composition of reportable segments discussed in Notes 1 and 9 to the consolidated financial statements, and (3) for reclassifications to certain financial statement captions to conform the presentation of the consolidated financial statements to industry-specific norms discussed in Notes 1 and 16 to the consolidated financial statements. Our procedures included evaluating the comparability of the retrospective application to each of the items described above. In our opinion, such retrospective adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2011 or

2010 consolidated financial statements of the Company other than with respect to the retrospective adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2011 or 2010 consolidated financial statements taken as a whole.

/s/ Ehrhardt Keefe Steiner & Hottman PC
Denver, Colorado
September 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
Magellan Petroleum Corporation
Portland, Maine

We have audited, before the effects of the retrospective adjustments (1) for the adoption of Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, as amended ("ASU 2011-5"), (2) to the disclosures for a change in the composition of reportable segments, and (3) for reclassifications to certain financial statement captions to conform the presentation of the financial statements to industry-specific norms discussed in Notes 1 and 16 to the consolidated financial statements, the consolidated balance sheet of Magellan Petroleum Corporation and subsidiaries (the "Company") as of June 30, 2011, and the related consolidated statements of operations, changes in equity and comprehensive loss, and cash flows for the years ended June 30, 2011 and June 30, 2010 (the 2011 and 2010 consolidated financial statements before the effects of the adjustments discussed in Notes 1 and 16 to the consolidated financial statements are not presented herein). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2011 and 2010 consolidated financial statements, before the effects of the retrospective adjustments for the adoption of ASU 2011-5, to the disclosures for a change in the composition of reportable segments, and for reclassifications to certain financial statement captions, which are discussed in Notes 1 and 16 to the consolidated financial statements, present fairly, in all material respects, the financial position of Magellan Petroleum Corporation and subsidiaries as of June 30, 2011, and the results of their operations and their cash flows for the years ended June 30, 2011 and 2010, in conformity with accounting principles generally accepted in the United States of America.

We were not engaged to audit, review, or apply any procedures to the retrospective adjustments for the adoption of ASU 2011-5, to the disclosures for a change in the composition of reportable segments or for reclassifications to certain financial statement captions, discussed in Notes 1 and 16 to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

/s/ Deloitte & Touche LLP
Hartford, Connecticut
September 20, 2011

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share amounts)

	June 30,	
ASSETS	2012	2011
CURRENT ASSETS:		
Cash and cash equivalents	$41,215	$20,417
Accounts receivable — trade (net of allowance for doubtful accounts of $0 and $66 as of June 30, 2012, and 2011, respectively)	1,152	4,357
Accounts receivable — working interest partners	231	454
Deposit on Evans Shoal	—	10,745
Inventories	499	732
Prepaid assets	498	517
Other assets	13	62
Total current assets	43,608	37,284
PROPERTY AND EQUIPMENT, NET (SUCCESSFUL EFFORTS METHOD):		
Proved oil and gas properties	33,927	136,094
Less accumulated depletion, depreciation, and amortization	(5,740)	(115,917)
Unproved oil and gas properties	7,091	3,368
Wells in progress	3,744	4,315
Land, buildings and equipment (net of accumulated depreciation of $2,077 and $3,985 as of June 30, 2012, and 2011, respectively)	1,422	1,293
Net property and equipment	40,444	29,153
OTHER NON-CURRENT ASSETS		
Securities available for sale	155	238
Goodwill	2,174	4,695
Deferred income taxes	5,951	—
Other long term assets	242	204
Total other non-current assets	8,522	5,137
Total assets	$92,574	$71,574
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Short term line of credit	$50	$1
Current portion of note payable	480	552
Current portion of asset retirement obligations	329	—
Accounts payable	3,672	3,861
Accrued and other liabilities	3,000	2,055
Total current liabilities	7,531	6,469
LONG TERM LIABILITIES:		
Note payable	390	870
Asset retirement obligations	7,455	11,397
Contingent consideration payable	4,072	—
Other long term liabilities	218	310
Total long term liabilities	12,135	12,577

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COMMITMENTS AND CONTINGENCIES (Note 10)		
Equity:		
Common stock (par value $.01 per share): Authorized 300,000,000 shares, outstanding, 53,835,594 and 52,455,977 as of June 30, 2012 and 2011, respectively	538	525
Capital in excess of par value	90,753	93,617
Preferred stock (par value $.01 per share): Authorized 50,000,000 and 0 shares, outstanding, 0 and 0 as of June 30, 2012 and 2011, respectively	—	—
Accumulated deficit	(29,590)	(56,073)
Accumulated other comprehensive income	11,207	12,470
Total equity attributable to Magellan Petroleum Corporation	72,908	50,539
NON-CONTROLLING INTEREST IN SUBSIDIARIES	—	1,989
Total equity	72,908	52,528
Total liabilities and equity	$92,574	$71,574

The accompanying notes are an integral part of these consolidated financial statements.

MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the years ended June 30,		
	2012	2011	2010
REVENUES:			
Oil production	$12,405	$11,815	$9,887
Gas production	1,353	1,796	13,616
Other	(46)	4,565	5,022
Total revenues	13,712	18,176	28,525
OPERATING EXPENSES:			
Lease operating	12,897	9,247	10,116
Depletion, depreciation, amortization, and accretion	1,744	2,890	5,428
Exploration	6,291	2,854	1,273
General and administrative	13,091	16,307	14,023
Impairment	328	173	2,050
Loss on Evans Shoal	—	15,893	—
Gain on sale of assets	(40,413)	(969)	(6,817)
Total operating (income) expense	(6,062)	46,395	26,073
Income (loss) from operations	19,774	(28,219)	2,452
Other income (expense)			
Warrant expense	—	—	(4,276)
Net interest income	749	923	1,038
Other income	9	—	1,975
Total other income (expense)	758	923	(1,263)
Income (loss) before income tax	20,532	(27,296)	1,189
Income tax benefit (provision)	5,951	(5,141)	(2,646)
Net income (loss) after income tax	26,483	(32,437)	(1,457)
Net loss attributable to non-controlling interest in subsidiaries	15	5	11
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)
Earnings per common share (Note 8)			
Weighted average number of basic shares outstanding	53,592,958	52,398,936	51,410,596
Weighted average number of diluted shares outstanding	54,041,227	52,398,936	51,410,596
Net income (loss) per basic share outstanding	$0.49	$(0.62)	$(0.03)
Net income (loss) per diluted share outstanding	$0.49	$(0.62)	$(0.03)

The accompanying notes are an integral part of these consolidated financial statements.

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	For the years ended June 30, 2012	2011	2010
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)
Foreign currency translation adjustments	(1,180)	9,308	1,358
Unrealized holding (losses) gains on securities available for sale, net of deferred tax of $0	(83)	46	(222)
Total comprehensive income (loss)	25,235	(23,078)	(310)
Net loss attributable to non-controlling interest in subsidiary	(15)	(5)	(11)
Comprehensive income (loss) attributable to Magellan Petroleum Corporation	$25,220	$(23,083)	$(321)

The accompanying notes are an integral part of these consolidated financial statements.

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except share and per share amounts)

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Income	Non-Controlling Interest	Total Stockholders' Equity
Balance June 30, 2009	41,500,325	$416	$73,311	$(22,195)	$1,980	$ —	$53,512
Net loss	—	—	—	(1,446)	—	(11)	(1,457)
Foreign currency translation adjustments	—	—	—	—	1,358	—	1,358
Unrealized holding loss on securities available for sale, net of taxes	—	—	—	—	(222)	—	(222)
Stock and stock based compensation	440,000	4	2,301	—	—	—	2,305
Equity investment by YEP	8,695,652	87	7,528	—	—	—	7,615
Warrants issued	—	—	6,402	—	—	—	6,402
Acquisition of controlling interest	1,700,000	17	2,363	—	—	1,925	4,305
Balance June 30, 2010	52,335,977	524	91,905	(23,641)	3,116	1,914	73,818
Net loss	—	—	—	(32,432)	—	(5)	(32,437)
Foreign currency translation adjustments	—	—	—	—	9,308	—	9,308
Unrealized holding gain on securities available for sale, net of taxes	—	—	—	—	46	—	46
Stock and stock based compensation	90,000	1	1,669	—	—	—	1,670
Stock options exercised	30,000	—	43	—	—	—	43
Capital contribution	—	—	—	—	—	80	80
Balance June 30, 2011	52,455,977	525	93,617	(56,073)	12,470	1,989	52,528
Net income	—	—	—	26,498	—	(15)	26,483
Foreign currency translation adjustments	—	—	—	—	(1,180)	—	(1,180)
Unrealized holding loss on securities available for sale, net of taxes	—	—	—	—	(83)	—	(83)

Stock and stock based compensation	175,000	2	1,558	—	—	—	1,560
Stock options exercised	21,875	—	35	—	—	—	35
Acquisition of non-controlling interest	927,352	9	(4,844)	(15)	—	(1,974)	(6,824)
Acquisition of working interest	255,390	2	387	—	—	—	389
Balance June 30, 2012	53,835,594	$538	$90,753	$(29,590)	$11,207	$ —	$72,908

The accompanying notes are an integral part of these consolidated financial statements.

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the years ended June 30,		
	2012	2011	2010
OPERATING ACTIVITIES:			
Net income (loss) after income tax	$26,483	$(32,437)	$(1,457)
Adjustments to reconcile net loss to net cash used in operating activities			
Foreign transaction (gain) loss	(1,038)	499	732
Write off of the Evans Shoal deposit	—	15,893	—
Depletion, depreciation, and amortization	1,744	2,890	5,428
Interest earned on restricted deposits	(24)	(150)	—
Fair value increase of contingent consideration payable	(79)	—	—
Deferred income taxes	(5,951)	5,355	922
Gain on disposal of assets	(40,413)	(969)	(6,817)
Gain on sale of investments	—	—	(1,975)
Exploration costs previously capitalized	2,930	(124)	—
Stock based compensation	1,560	1,670	6,582
Related party withholding tax (Note 11)	1,082	—	—
Impairment loss	328	239	2,050
Net changes in operating assets and liabilities:			
Accounts receivable	3,021	625	2,733
Inventories	142	143	647
Prepayments and other current assets	(36)	213	(106)
Accounts payable and accrued liabilities	(138)	613	(1,689)
Other long term liabilities	(113)	—	—
Income taxes payable	61	1,045	(3,098)
Net cash (used in) provided by operating activities	(10,441)	(4,495)	3,952
INVESTING ACTIVITIES:			
Additions to property and equipment	(9,577)	(4,568)	(2,843)
Proceeds from sale of assets	35,089	1,481	7,280
Purchase of working interest in Poplar	(823)	(380)	(4,090)
Cash acquired from controlling interest purchase - Nautilus Poplar LLC	—	—	315
Increase in restricted cash	—	—	(75)
Refund (Payment) of Deposit for Purchase of Evans shoal (includes interest)	10,940	(10,014)	(13,752)
Proceeds from sale of securities	—	—	465
Securities matured or sold	5,687	7,000	16,809
Securities purchased	(5,687)	(7,000)	(13,456)
Net cash provided by (used in) investing activities	35,629	(13,481)	(9,347)
FINANCING ACTIVITIES:			
Proceeds from issuance of stock	35	43	10,000
Short term debt issuances	6,075	5,027	570
Short term debt repayments	(6,025)	(4,589)	(845)
Purchase of non-controlling interest - Nautilus Poplar LLC	(3,461)	—	(7,309)
Non-controlling capital contribution - Nautilus Poplar LLC	—	80	—
Long term debt repayments	(552)	—	—
Net cash (used in) provided by financing activities	(3,928)	561	2,416

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Effect of exchange rate changes on cash and cash equivalents	(462)	4,240	1,882
Net increase (decrease) in cash and cash equivalents	20,798	(13,175)	(1,097)
Cash and cash equivalents at beginning of period	20,417	33,592	34,689
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$41,215	$20,417	$33,592
Cash payments (receipts):			
Income taxes	—	(1,259)	4,822
Interest paid, net of amount capitalized	109	141	62
Supplemental schedule of non-cash investing and financing activities:			
Unrealized holding gain (loss)	(83)	46	—
Revision to estimate of asset retirement obligation	(603)	(129)	(2,232)
Accounts payable related to property, plant, and equipment	155	8	48
Purchase of non-controlling interest for stock and contingent consideration	4,729	—	—
Purchase of 3% working interest for stock and contingent consideration	1,243	—	—

The accompanying notes are an integral part of these consolidated financial statements.

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MAGELLAN PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 - Basis of Presentation
Description of Operations
Magellan Petroleum Corporation (the "Company" or "Magellan" or "we" or "us") is an independent energy company engaged in the acquisition, exploration, exploitation, development, production, and sale of crude oil and natural gas. As of June 30, 2012, Magellan had two reporting segments: (i) a 100% membership interest in Nautilus Poplar LLC ("NP"), based in Denver, Colorado, and (ii) a 100% equity interest in its subsidiary, Magellan Petroleum Australia Limited ("MPAL"), headquartered in Brisbane, Australia, which includes our operations in the United Kingdom.
Basis of Presentation
The accompanying consolidated financial statements include the accounts of Magellan and its wholly owned subsidiaries, NP and MPAL, and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and the instructions to Form 10-K and Regulation S-X. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.
All amounts presented are in United States dollars, unless otherwise noted. Amounts expressed in Australian currency are indicated as "AUD."
Reclassification
As of December 31, 2011, we have changed the presentation of our financial statements to conform them to industry-specific norms and to improve our reporting to shareholders and stakeholders. Specifically, we have modified the presentation of expenses in the consolidated statements of operations and the presentation of property and equipment in the consolidated balance sheets. As a result, certain reclassifications have been made to the prior period financial statements to align them with this revised presentation format, there was no impact on previously reported results (see Note 16).
Use of Estimates
The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.
Foreign Currency Translation
The functional currency of our foreign subsidiaries is their local currency. Assets and liabilities of foreign subsidiaries are translated to United States dollars at period-end exchange rates, and our consolidated statements of operations and cash flows are translated at average exchange rates during the period. Resulting translation adjustments are recorded as a separate component of stockholders' equity as accumulated other comprehensive income (loss).
Transactions denominated in currencies other than the local currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in foreign currency transaction gains and losses that are reflected in results of operations as unrealized (based on period end translation) or realized (upon settlement of the transactions) and reported under general and administrative expenses.
Cash and Cash Equivalents and Concentration of Credit Risk
The Company considers all highly liquid short term investments with original maturities of three months or less at the date of acquisition to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments.
The Company's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents. Large balances of cash and cash equivalents were held in several Australian banks in time deposit accounts that have terms of 90 days or less. The Company regularly assesses the level of credit risk we are exposed to and whether there are better ways of managing credit risk. The Company invests its cash and cash equivalents with reputable financial institutions. At times, balances deposited may exceed FDIC insured limits. The Company has not incurred any losses related to these deposits.

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Accounts Receivables and Allowance for Doubtful Accounts

Trade accounts receivable consist mainly of receivables from oil and gas purchasers. For receivables from working interest partners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and gas receivables are collected within two months. We continuously monitor collectability of accounts receivables and use our judgment in establishing a provision for allowance for doubtful accounts based upon our historical experience and any specific customer collection issues we identify.

Inventories

Our inventories consist of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials, and parts and production equipment for use in future drilling operations or repair operations. All inventories are carried at the lower of cost or net realizable value.

Oil and Gas Exploration and Production Activities

The Company follows the successful efforts method of accounting for its oil and gas exploration and production activities. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense and included within the consolidated statement of cash flows and reported as capital expenditures under investing activities. The costs of development wells are capitalized whether those wells are successful or unsuccessful.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred to exploration expense. Depreciation, depletion, and amortization ("DD&A") of capitalized costs related to proved oil and gas properties is calculated on a property-by-property basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. The Company records its proportionate share in joint venture operations in the respective classifications of assets, liabilities, and expenses.

The sale of a partial interest in a proved oil and gas property is accounted for as normal retirement, and no gain or loss is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. A gain or loss is recognized for all other sales of producing properties and is included in the accompanying consolidated statements of operations.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of estimated future cash flows, net of estimated operating and development costs, using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

Land, Buildings, and Equipment

Land, buildings, and equipment and field equipment are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets which range from three to fifteen years.

Securities Available for Sale

Securities available for sale are comprised of investments in publicly traded securities and are carried at quoted market prices. Unrealized gains and losses are excluded from earnings and recorded as a component of accumulated other comprehensive income in shareholders' equity, net of deferred income taxes, until realized.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. GAAP requires goodwill to be evaluated on an annual basis for impairment, or more frequently if events occur or circumstances change that could potentially result in impairment. We adopted the new guidance for our annual impairment test in 2012 as allowed by ASU 2011-08, and therefore performed an assessment of qualitative factors for our annual impairment test in 2012 resulting in the conclusion that there is no impairment of goodwill.

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The qualitative factors used in our assessment include macroeconomic conditions, industry and market conditions, cost factors, and overall financial performance.
The Company has determined that it has two reporting units, NP and MPAL. Historical goodwill in the amount of $0.7 million relates to the acquisition of a majority ownership stake in NP and $4.0 million relates to the acquisition of and additional ownership interest in MPAL. The decrease in goodwill during fiscal 2012 relates to the disposition of a portion of the MPAL reporting segment associated with the Santos SA (see Note 2). As of June 30, 2012, $1.5 million of recorded goodwill related to MPAL, and $0.7 million related to NP.
The change in the carrying amount of goodwill can be summarized as follows:

	June 30, 2012 (In thousands)
Fiscal year ended June 30, 2011	$4,695
Sale of Mereenie interests (see Note 2)	2,521
Fiscal year ended June 30, 2012	$2,174

Asset Retirement Obligations
The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is acquired or the liability to plug is legally incurred. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs, net of estimated salvage values, and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties (see Note 4).
Revenue Recognition
The Company derives revenue primarily from the sale of produced oil and gas. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. Other production related revenues correspond primarily to the Company's share of gas pipeline tariff revenues which are recorded on a gross basis at the time of sale. Transportation costs are included in production costs.
Major Customers
For our NP reporting segment, revenue from a single customer accounted for approximately 45%, 30%, and 8% of the Company's consolidated oil and gas production revenue for the years ended June 30, 2012, 2011, and 2010, respectively. For our MPAL reporting segment, revenue from one customer accounted for approximately 45%, 35% , and 25% of consolidated oil and gas production revenues for the years ended June 30, 2012, 2011, and 2010, respectively; revenue from another customer accounted for approximately 8%, 11%, and 10% of consolidated oil and gas production revenues in the same periods, respectively.
Preferred Stock
The Company has 50.0 million shares of preferred stock authorized, par value $0.01 per share, issuable from time to time in one or more series issuable at the discretion of the Company's Board of Directors. As of June 30, 2012, and 2011, no preferred stock was outstanding.
Stock Based Compensation
The Company records compensation expense for time based options on a straight-line basis over the vesting period. Performance based options are recognized when the achievement of the performance conditions is considered probable. We estimate the fair value of all performance and non-performance based stock options using the Black-Scholes-Merton pricing model. The fair value of the stock options is determined on the grant date and is affected by our stock price, and other assumptions regarding a number of complex and subjective variables. These variables include our expected stock price volatility over the term of the awards, risk free interest rates, expected dividends, and the expected option exercise term. The lack of historical data related to the exercise of options leads the Company to use the simplified method to estimate the expected term of options.
Accounting for Income Taxes

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The Company follows the liability method in accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The Company records a valuation allowance for deferred tax assets when it is more likely than not that such assets will not be recovered.

GAAP prescribes a comprehensive model for recognizing, measuring, presenting, and disclosing in the financial statements uncertain tax positions that the Company has taken or expects to take in its tax returns. Under GAAP, the Company recognizes tax positions when it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company has presumed that its positions will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The next step consists of measurement. A tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. A tax position is measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. An uncertain income tax position will not be recognized if it does not meet the more-likely-than-not threshold. To appropriately account for income tax matters, the Company is required to make significant judgments and estimates regarding the recoverability of deferred tax assets, the likelihood of the outcome of examinations of tax positions that may or may not be currently under review, and potential scenarios involving settlements of such matters. Changes in these estimates could materially impact the consolidated financial statements. There are no significant uncertain tax positions for either fiscal year 2012 or 2011.

The Company has adopted an accounting policy to record all tax related interest under the interest expense and tax related penalties under general and administrative expense in the consolidated statement of operations.

Financial Instruments

The carrying value for cash and cash equivalents, accounts receivable, marketable securities, accounts payable, and debt approximates fair value based on the timing of the anticipated cash flows and current market conditions.

Business Combinations

The Company applies the acquisition method of recording business combinations. Under this method, the Company recognizes and measures the identifiable assets acquired from, the liabilities assumed from, and any non-controlling interest in the acquiree. Any goodwill or gain is identified and recorded. We engage independent valuation consultants to assist us in determining the fair values of crude oil and natural gas properties acquired and other third party specialists as needed to assist us in assessing the fair value of other assets and liabilities assumed. These valuations require management to make significant estimates and assumptions, especially with respect to the oil and gas properties.

The fair value of contingent considerations are calculated using production projections and the estimated timing of production payouts. The Company also utilized a discount which is consistent with the rate used in valuing its asset retirement obligation and reflective of the Company’s credit adjusted incremental borrowing rate.

Segment Information

Prior to September 30, 2011, our reportable segments included Magellan ("Corporate"), NP, and MPAL. During the quarter ended September 30, 2011, Magellan completed a restructuring of its North American assets (see Note 2) resulting in a change to its reportable segments. Certain prior period groupings for the fiscal years ended June 30, 2011, and 2010, have been reclassified to conform to the current year segment presentation.

As of June 30, 2012, the Company had two reportable segments, NP and MPAL, as well as a head office which is treated as a cost center. The Company’s chief operating decision maker is J. Thomas Wilson (President and CEO of the Company) who reviews the results of the Australian and North American businesses on a regular basis. Both segments engage in business activities from which each may earn revenues and incur expenses. MPAL and its subsidiaries, which include our operations in the United Kingdom, are considered one segment.

Earnings (Loss) per Share

Income and losses per common share are based upon the weighted average number of common and common equivalent shares outstanding during the period. The reconciling items in the calculation of diluted earnings per share

are the dilutive effect of stock options, warrants, and restricted non-vested shares. The potential dilutive impact of non-vested shares is determined using the treasury stock method. The dilutive impact of stock options and warrants is also determined using the treasury stock method.

For the years ended June 30, 2012, 2011, and 2010, the Company had 7,522,826, 9,297,826, and 8,127,826 options and warrants outstanding, respectively, that had an exercise price below the average stock price that would have resulted in 448,269, 3,460,331, and 1,634,797, incremental dilutive shares, respectively. The Company also had 100,000, 104,167, and

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208,334 non-vested options for shares of Company stock that would have resulted in zero incremental dilutive shares for the years ended June 30, 2012, 2011, and 2010. There were no other potentially dilutive items for the years ended June 30, 2012, 2011, and 2010. There was no dilutive effect on earnings per share for years ended June 30, 2011, and 2010, as a result of net losses.

Accumulated Other Comprehensive Income (Loss)

Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of stockholders' equity and comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net income (loss).

Recently Issued Accounting Standards

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and IFRS ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, Fair Value Measurement. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards. The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. These amendments did not have a significant impact on companies applying GAAP. ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this standard did not have an impact on the Company's consolidated financial statements other than additional disclosures (see Note 5).

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (amended further under ASU No. 2011-12 in December 2011). This guidance eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. The guidance allows two presentation alternatives: present items in net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income; or present items in two separate, but consecutive, statements of net income and other comprehensive income. This guidance is is effective for interim and annual periods beginning after December 15, 2011. Full retrospective application is required under both sets of accounting standards. The adoption of this standard did not have an impact on the Company's consolidated financial statements.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles – Goodwill and Other: Testing Goodwill for Impairment ("ASU 2011-08"), which provides amendments to FASB ASC Topic 350, Intangibles – Goodwill and Other. The objective of ASU 2011-08 is to simplify how entities test goodwill for impairment. The amendment provides an entity with the option to first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in Topic 350. ASU 2011-08 is effective for interim and annual goodwill impairment tests performed for annual periods beginning after December 15, 2011. The adoption of this standard did not have an impact on the Company's consolidated financial statements.

Note 2 - Acquisitions and Divestitures

Evans Shoal Agreement. During the year ended June 30, 2010, MPAL entered into an agreement with Santos Offshore Pty Ltd to purchase Santos' 40% interest in the Evans Shoal natural gas field (NT/P48). On July 22, 2011, this agreement was terminated, and MPAL received a deposit refund from Santos of AUD $10.0 million, plus interest, pursuant to the terms of the agreement.

Sale Agreement between Magellan Petroleum (N.T.) Pty Ltd and Santos QNT Pty Ltd and Santos Limited. On May 25, 2012, Magellan Petroleum (N.T.) Pty Ltd ("Magellan NT"), a wholly owned subsidiary of MPAL, and Santos QNT Pty Ltd ("Santos QNT") and Santos Limited (collectively the "Santos Entities") completed a Sale Agreement (the "Santos SA"), referred to herein as the "Santos Transaction" and became the sole owner of the Palm Valley Interests (as defined below) and of the Dingo Interests (as defined below), while Santos became the sole owner of the Mereenie Interests (as defined below). In accordance with the terms of the Santos SA, the Santos Transaction is deemed to be effective as of July 1, 2011. The Santos SA resulted in net cash proceeds of $26.6 million, including adjustments of $1.1 million, and a gain on sale of assets in the amount of $36.2 million. The Santos SA provided for the transfer of the following assets:

- Magellan NT's 35% interest in each of the Mereenie Operating Joint Venture and the Mereenie Pipeline Joint Venture (collectively, the "Mereenie Interests") to Santos QNT;
- The Santos Entities' combined interests of 48% in the Palm Valley Joint Venture ("Palm Valley Interests") and combined interests of 66% in the Dingo Joint Venture ("Dingo Interests") to Magellan NT.

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Pursuant to the Santos SA, Magellan NT is also entitled to a series of contingent payments. The Company has not recognized a contingent asset related to the series of contingent payments, as such amounts are not reasonably assured. The Company accounted for the Santos SA using the relative fair value method of accounting, which allocates the fair value of the assets received in the asset transfer to the Palm Valley Interests and the Dingo Interests. No goodwill or other intangible assets were recorded as a result of the Santos SA. However, goodwill in the amount of $2.5 million was recorded as a component of the gain on sale of assets. The purchase price allocation was considered final as of June 30, 2012.

The following table summarizes the allocation of the consideration received for the assets transferred as a result of the Santos SA as of June 30, 2012.

	Total (In thousands)
Consideration received	
Net purchase price per Santos SA	$25,493
Purchase price adjustments	1,138
Total	$26,631
Allocation of the consideration received to fair value of assets	
Proved oil and gas properties (Palm Valley)	$3,403
Unproved oil and gas properties (Dingo)	2,957
Land, buildings, and equipment (Palm Valley)	370
Total allocation of the fair value received	6,730
Mereenie liabilities given up, net	2,805
Gain on sale of assets	(36,166)
Total	$(26,631)

The Santos SA is deemed to be effective as of July 1, 2011. The following unaudited pro forma financial information presents combined results of the Santos SA, and assumes a transaction date of July 1, 2010. The pro forma financial information is presented for informational purposes and is not indicative of the results of operations that would have been achieved if the acquisition had taken place at July 1, 2010. The unaudited pro forma results can be summarized as follows for the years ended:

	Magellan as Reported	Pro Forma Acquisition [(a)]	Disposition [(b)]	Combined
	(In thousands, except per share amounts)			
June 30, 2012				
Sales	$13,712	$1,025	$(5,891)	$8,846
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(223)	$835	$27,110
Net income per basic share outstanding	$0.49			$0.51
Net income per diluted share outstanding	$0.49			$0.50
June 30, 2011				
Sales	$18,176	$4,492	$(8,813)	$13,855
Net (loss) income attributable to Magellan Petroleum Corporation	$(32,432)	$2,471	$(1,144)	$(31,105)
Net (loss) per basic share outstanding	$(0.62)			$(0.59)
Net (loss) per diluted share outstanding	$(0.62)			$(0.59)

(a) Reflects the pro forma results from operations related to the Palm Valley Interests and the Dingo Interests.

(b) Reflects the pro forma results from operations related to the Mereenie Interests.

Lease Purchase and Sale and Participation Agreement with VAALCO Energy (USA), Inc. ("VAALCO"). On September 6, 2011, the Company entered into a Lease Purchase and Sale and Participation Agreement (the

"VAALCO PSA") with VAALCO. Pursuant to the VAALCO PSA, the Company received $5.0 million in cash, and VAALCO received an undivided 65% of the Company’s working interest in formations below the top of the Bakken/Three Forks (the "Deep Intervals") in Poplar.

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The accounting for this transaction is set forth in the table below:

	Total (In thousands)
Cash consideration received	$5,000
Net book value allocated to Deep Intervals	(829)
Transaction costs	(162)
Gain on sale recognized	$4,009

Acquisition of Non-Controlling Interest in Nautilus Poplar LLC and Acquisition of Additional Working Interests. On September 2, 2011, the Company entered into a Purchase and Sale Agreement (the "Nautilus PSA") between the Company and the non-controlling interest owners of NP, being the Nautilus Technical Group, LLC ("NT") and Eastern Rider, LLC ("ER") (the "Nautilus Sellers"). The Nautilus Sellers included J. Thomas Wilson (a Magellan director and now its President and CEO), a second individual who has served as a consultant to NP, and a third individual who was an employee of NP at the time of the transaction, as well as certain other persons.

The Nautilus PSA provided for the Company's purchase of all membership interests from the Nautilus Sellers in return for (i) $4.0 million in cash (the "Cash Consideration"), (ii) $2.0 million, less certain costs and certain debt owed to Magellan by the Nautilus Sellers, in unregistered shares of Magellan's common stock, par value $0.01 (the "Net Share Consideration"), and (iii) the potential for future production payments ("Contingent Production Payments"), payable in cash to the Nautilus Sellers, collectively, of up to $5.0 million if certain increased average daily production milestones are achieved. The shares were sold pursuant to Section 4(2) of the Securities Act of 1933. The Cash Consideration was transferred on September 2, 2011. Consistent with the terms of the Nautilus PSA, 1,182,742 of shares in the Net Share Consideration were issued on September 23, 2011. J. Thomas Wilson's interest in this transaction approximated 52% of the consideration paid to the Nautilus Sellers.

The discounted fair value of the future contingent consideration payable is calculated at the end of each fiscal quarter using consistent assumptions and methodology. As of June 30, 2012, the contingent consideration payable was valued at $4.07 million and is reported in the consolidated balance sheet as contingent consideration payable.

The acquisition of NT's direct working interests was treated as a business combination for accounting purposes. The fair value of assets acquired and liabilities assumed were recorded at estimated fair value. This estimate was made based on significant unobservable (Level 3) inputs and based on the best information available at the time (see Note 5). A de minimis amount of revenues and earnings related to the working interests acquired is included in the accompanying consolidated statements of operations for the year ended June 30, 2012.

The table below summarizes the consideration paid to the Nautilus Sellers under the Nautilus PSA and the estimated fair value of the assets acquired and liabilities assumed for the working interests acquired from NT.

	NT non-controlling interest in NP (In thousands)	NT working interest in Poplar	ER non-controlling interest in NP	Total
Consideration paid to Sellers (1):				
Cash consideration	$1,920	$823	$1,257	$4,000
Share consideration (2)	907	389	526	1,822
Fair value of contingent consideration payable	1,993	854	1,304	4,151
Total	$4,820	$2,066	$3,087	$9,973

	Total (In thousands)
Recognized amount of identifiable assets acquired and liabilities assumed for Business combination:	
Oil and gas assets (proved)	$1,462
Oil and gas assets - Deep Intervals (unproved)	679
ARO liability	(75)

Total	$2,066

(1) Excludes transaction costs.
(2) Common stock valued at $1.54 per share closing price on the date of the transaction.

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Note 3 - Debt

Long term debt relates to a $1.7 million note payable re-issued in January 2011. This note will be fully amortized in June 2014, and the outstanding principal consisted of the following for the years ended:

	June 30, 2012	2011
	(In thousands)	
Note payable	$870	$1,422
Less current portion of note payable	(480)	(552)
Long term debt, excluding current portion	$390	$870

As of June 30, 2012, the minimum future principal maturities of long term debt were as follows:

	June 30, 2012 (In thousands)
One year	$480
Two years	390
Total	$870

The variable rate of the note is based upon the Wall Street Journal Prime Rate (the "Index") plus 1.00%, subject to a floor rate of 6.25%. The Index was 3.25% at June 30, 2012, resulting in an interest rate of 6.25% per annum as of June 30, 2012. Under the note payable, NP is required to maintain certain customary financial and restrictive covenants. As of June 30, 2012, NP was in compliance with all financial and restrictive covenants.

In addition, the Company has a $1.0 million working capital line of credit classified as short term debt. The amount due on the line of credit was $0.1 million as of June 30, 2012. The line of credit bears interest at a variable rate, which was 6.25% as of June 30, 2012. The line of credit also secures both a letter of credit in the amount of $25 thousand in favor of the Bureau of Land Management and business credit cards in the amount of $25 thousand. As of June 30, 2012, $0.9 million was available under this line of credit.

The note payable, letters of credit, and business credit cards are collateralized by a first mortgage and an assignment of production for Poplar and are guaranteed by Magellan up to $6.0 million, not to exceed the amount of the principal owed.

The carrying amount of the Company’s long term debt approximates its fair value, due to its variable interest rate, which resets based on the market rates.

Note 4 - Asset Retirement Obligations

The estimated valuation of asset retirement obligations ("AROs") are based on management's historical experience and best estimate of plugging and abandonment costs by field. Assumptions and judgments by management include determination of the existence of a legal obligation for an ARO; estimated probabilities, amounts, and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Accretion expense is recorded under depletion, depreciation, amortization, and accretion in the consolidated statement of operations.

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The following table summarizes the asset retirement obligation activity for the years ended:

	June 30, 2012	2011
	(In thousands)	
Balance at beginning of year	$11,397	$9,292
Liabilities assumed	3,035	—
Liabilities incurred	398	50
Accretion expense	568	564
Sale of assets	(6,773)	—
Revision to estimate	(603)	(129)
Effect of exchange rate changes	(238)	1,620
Balance at end of year	7,784	11,397
Less current asset retirement obligation	329	—
Long term asset retirement obligation	$7,455	$11,397

Note 5 - Fair Value Measurements

The Company follows authoritative guidance related to fair value measurement and disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted prices in active markets for identical assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant other observable inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant unobservable inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company's policy is to recognize transfers in and/or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Company has consistently applied the valuation techniques discussed for all periods presented.

Items required to be measured at fair value on a nonrecurring basis include the assets acquired and liabilities assumed related to the acquisition of an additional 3% working interest in Poplar, assets acquired as a result of the Santos SA (see Note 2), and liabilities related to AROs.

Items required to be measured at fair value on a recurring basis include securities available for sale, classified as Level 1, and the contingent consideration payable (see Note 2), classified as Level 3.

As of June 30, 2012, the Company had$41.2 million in cash and cash equivalents, with $2.7 million held in cash and $38.6 million classified as cash equivalents. The cash equivalents were held in time deposit accounts in several Australian banks with maturities of 90 days or less.

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The following table presents the amounts of assets and liabilities carried at fair value by the level in which they are classified within the valuation hierarchy for the years ended:

	June 30, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Cash and cash equivalents	$41,215	$—	$—	$41,215
Securities available for sale	155	—	—	155
	$41,370	$—	$—	$41,370
Liabilities				
Contingent consideration payable	$—	$—	$4,072	$4,072

	June 30, 2011			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Cash and cash equivalents	$20,417	$—	$—	$20,417
Securities available for sale	238	—	—	238
	$20,655	$—	$—	$20,655

During the years ended June 30, 2012, and 2011, there have been no transfers in and out of Level 1, Level 2, or Level 3.

The following table presents a roll forward of liabilities measured at fair value using significant unobservable inputs (Level 3) as of:

	June 30, 2012
	(In thousands)
Balance at beginning of year	$—
Contingent consideration payable addition	4,072
Balance at end of year	$4,072

Note 6 - Income Taxes

The domestic and foreign components of our income (loss) before income taxes are as follows for the years ended:

	June 30, 2012	2011	2010
	(In thousands)		
Domestic	$(6,646)	$(6,780)	$(8,456)
Foreign	27,178	(20,516)	9,645
Net income (loss) after income tax	$20,532	$(27,296)	$1,189

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The following reconciles the Company's effective tax rate to the federal statutory tax rate for the years ended:

	June 30, 2012	2011	2010
	(In thousands)		
Tax provision computed per federal statutory rate	$6,160	$(8,088)	$356
State taxes, net of federal benefit	190	(201)	244
Foreign rate differential	76	(271)	(338)
Non taxable Australian revenue	(8)	(822)	(953)
Non deductible warrant and stock related compensation	—	—	2,203
Goodwill write off	756	—	—
Decreases related to lapse of applicable statute of limitations	1,571	—	—
Change in valuation allowance	9,352	17,135	(346)
Australian petroleum resource rent tax	(5,951)	—	—
Australian petroleum resource rent tax - income tax effect	1,785	—	—
Magellan capitalized facilitation costs	—	106	201
Taxable dividends from subsidiaries, net of foreign tax credits	(1,152)	932	1,690
Foreign tax credit adjustment	649	(3,411)	—
Capital loss adjustment	(3,006)	—	—
Additional basis related to the Santos SA	(18,118)	—	—
Impact of rate change	457	—	—
Foreign currency translation differential	1,375	—	—
Other	(87)	(239)	(411)
Consolidated income tax (benefit) provision	$(5,951)	$5,141	$2,646

Components of our income tax provision can be summarized as follows:

	June 30, 2012	2011	2010
	(In thousands)		
Current income tax			
United States			
Federal tax	$—	$—	$—
State tax (benefit) provision	—	(127)	375
Foreign tax (benefit) provision	—	(87)	1,349
Total current income tax (benefit) provision	—	(214)	1,724
Deferred income tax			
United States deferred tax (benefit) provision	—	(195)	195
Foreign tax provision (benefit)	(5,951)	5,550	727
Total deferred income tax (benefit) provision	(5,951)	5,355	922
Consolidated income tax (benefit) provision	$(5,951)	$5,141	$2,646
Effective tax rate	(29)%	(19)%	223%

The Company's effective tax rate was reduced to negative 29% primarily due to the recognition of the onshore Australian Petroleum Resource Rent Tax ("PRRT") deferred tax asset.

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Significant components of the Company's deferred tax assets and liabilities can be summarized as follows for the years ended:

	June 30, 2012	2011
	(In thousands)	
Deferred tax liabilities		
Land, buildings and equipment	$(2,767)	$—
Stepped up basis of oil and gas properties	(550)	(690)
Australian petroleum resource rent tax - income tax effect	(1,785)	—
Other	(261)	(901)
Total deferred tax liabilities	(5,363)	(1,591)
Deferred tax assets		
Acquisition and development costs	—	3,234
Asset retirement obligations	2,210	2,993
Net operating losses, capital losses, and foreign tax credit carry forwards	28,139	12,188
Australian petroleum resource rent tax	5,951	—
United Kingdom exploration costs and net operating losses	3,224	2,358
Stock option compensation	1,851	1,673
Interest	539	539
Australian capitalized legal costs	514	426
Other	579	521
Total deferred tax asset	43,007	23,932
Valuation allowance	(31,693)	(22,341)
Net long term deferred tax asset	$5,951	$—

For the fiscal year ended June 30, 2012, the valuation allowance increased by $9.4 million, primarily due to additional capital losses available for MPAL related to the Santos SA.

During the fiscal year ended June 30, 2011, the Company did not expect to remit undistributed earnings of our foreign subsidiaries to the U.S. in the foreseeable future. Federal and State Income Taxes were therefore not provided on accumulated but undistributed earnings of foreign subsidiaries, because such earnings were considered permanently reinvested in the business. During the fiscal year ended June 30, 2012, the Company changed its position with respect to permanently reinvesting its undistributed earnings. The Company determined that $20.0 million of undistributed earnings of its wholly-owned foreign subsidiary, MPAL, would be remitted to the U.S. in the foreseeable future. The Company does not anticipate any future Federal or State Income Tax effect as a result of this repatriation of foreign earnings due to the utilization of available foreign tax credit carry forwards.

The tax benefit recorded for fiscal year 2012 totals $6.0 million. In addition to corporate income tax, the income tax benefit includes the tax effect of the Company's obligation related to the Australian PRRT. The extension of PRRT to onshore projects was enacted during fiscal year 2012 and effective from July 1, 2012. As a consequence of the extension of the Australian PRRT regime to onshore petroleum products, a deferred tax benefit related to the Palm Valley gas field of $6.0 million in respect of the starting base of $16.6 million (which is net of AROs, and claimable against future PRRT liabilities) was recorded.

The United States gross deferred tax asset at June 30, 2012, consists primarily of foreign tax credits. The Australian gross deferred tax asset at June 30, 2012, consists primarily of acquisition and development costs, asset retirement obligations, net operating and capital loss carry forwards, and other assets which will result in tax deductions when paid. Australian net operating and capital losses carry forward indefinitely.

After reviewing all positive and negative evidence, a valuation allowance is still recorded against all the deferred tax assets, with exception of the $6.0 million deferred tax asset based on the Australian PRRT noted above.

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As of June 30, 2012, the Company remains subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction	Tax Years Subject to Exam:
U.S. Federal	2011
Montana	2010 - 2011
Australia	2008 - 2011

Subsequent to June 30, 2012, the IRS completed an examination of the Company's 2009 and 2010 annual return forms which resulted in no additional tax due and a reduction in the Company's foreign tax credit carry forward of $0.5 million.

At June 30, 2012, the Company had net operating loss and foreign tax credit carry forwards for U.S. Federal and State Income Tax purposes, respectively, which are scheduled to expire periodically as follows:

	Net Operating Losses		Federal
	Paroo USA Federal	State	Foreign Tax Credit
	(In thousands)		
Expires			
2013	$230	$—	$—
2017	—	—	310
2018	—	1,271	—
2019	96	—	1,411
2020	—	—	144
2021	25	—	886
2022	74	—	4,494
2023	3	—	—
2024	2	—	—
2025	1	—	—
Total	$431	$1,271	$7,245

The Company estimates that it has sufficient foreign tax credits to repatriate significant earnings and profits over and above the $20.0 million already repatriated from its foreign subsidiaries subsequent to the fiscal year ended June 30, 2012, without incurring additional U.S. income tax due to the utilization of available foreign tax credits.

During fiscal year 2012, the Company recorded a cumulative out of period adjustment in connection with U.S. Federal Tax Withholdings and related penalties and interest (see Note 11). The adjustment related to fiscal year 2010 and increased general and administrative expense in fiscal year 2012 by $0.9 million. Had this amount been reflected in fiscal year 2010, the period in which it arose, general and administrative expense, and accumulated deficit would have increased by $0.9 million. The impact on net loss per basic and diluted share attributable to Magellan Petroleum Corporation common shareholders would have been less than $0.02 had the amount been reflected in the period in which it arose. Based upon an evaluation of all relevant quantitative and qualitative factors, and after considering SEC Staff Accounting Bulletins Nos. 99 and 108, management believes that any amounts attributable to the years ended June 30, 2010, and 2011, and the impact of correcting such amounts in the year ended June 20, 2012, are not material to any of the Company's consolidated financial statements presented herein

There are no material uncertain tax positions for either fiscal 2012 or 2011.

Note 7 - Stock Based Compensation

The Stock Plan

On December 8, 2010, shareholders approved an amendment to the Company’s 1998 Stock Incentive Plan (the "Stock Plan") to increase the number of authorized common stock shares reserved for awards under the Stock Plan to a total of 7,205,000 shares. These authorized shares can take the form of non-qualified stock options, stock appreciation rights, restricted share awards, annual awards of stock to directors, and performance based awards ("PBOs").

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Stock Option Grants

Stock option grants contain both time based and performance based vesting provisions. The time based options are expensed on a straight-line basis over the vesting period. Performance based options are recognized when the achievement of the performance conditions is considered probable. Management re-assesses whether satisfaction of performance conditions are probable at the end of each reporting period. If changes in the estimated outcome of the performance conditions affect the quantity of the awards expected to vest, the cumulative effect of the change is recognized in the period of change. As of June 30, 2012, management believes the achievement of the performance conditions related to the performance based stock options is probable. Accordingly, the Company has begun to recognize expense on these awards over the period of time the performance condition is expected to be achieved.

As of June 30, 2012, 435,000 shares were available for future issuance under the Stock Plan. Of the 1,675,000 options granted during the current fiscal year, 295,750 were issued as PBOs and 825,000 options were issued outside of the Stock Plan. Options outstanding have expiration dates ranging from November 28, 2015, through January 10, 2022.

The following table summarizes the stock option activity for the years ended:

	June 30, 2012		2011		2010	
	Number of Shares	WAEPS [1]	Number of Shares	WAEPS [1]	Number of Shares	WAEPS [1]
Balance at beginning of year	5,200,000	$1.49	3,880,000	$1.26	3,242,500	$1.25
Granted	1,675,000	$1.10	1,750,000	$2.08	637,500	$1.33
Exercised	(21,875)	$1.60	(30,000)	$1.45	—	$0.00
Forfeited	(100,000)	$1.72	(400,000)	$1.84	—	$0.00
Options outstanding at year end	6,753,125	$1.44	5,200,000	$1.49	3,880,000	$1.26
Weighted average remaining contractual term		6.8 years		7.6 years		8.1 years

[1] Weighted average exercise price per share

At June 30, 2012, there was a total of $0.7 million in unrecognized stock compensation expense related to stock options granted. This cost is expected to be recognized over a weighted-average period of 1.4 years. The amount of unrecognized compensation expense noted above does not necessarily represent the amount that will ultimately be realized by the Company in its consolidated statement of operations. During the fiscal year ending June 30, 2013, it is expected that an additional 1,100,002 stock options will vest.

Cash received from the exercise of stock options for the years ended June 30, 2012, and 2011, was less than $0.1 million. No stock options were exercised during 2010.

The following table summarizes options outstanding and exercisable as of June 30, 2012:

	Options outstanding and exercisable		
Range of exercise prices	Number of shares	Weighted average remaining contractual life	Weighted average exercise price
$1.01 - $1.16	549,999	8.7 years	$1.12
$1.20 - $1.20	3,100,000	6.5 years	$1.20
$1.40 - $1.60	528,125	4.5 years	$1.54
$1.72 - $2.41	683,330	7.9 years	$2.18
	4,861,454		
Aggregate intrinsic value	$(1,851,313)		

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The fair value of shares issued under the Stock Plan was estimated using the following weighted-average assumptions for the years ended:

	June 30, 2012	2011	2010
Number of options	1,675,000	1,750,000	637,500
Weighted-average grant date fair value per share	$0.66	$1.10	$0.85
Expected dividend	$0.00	$0.00	$0.00
Risk free interest rate	1.0 % - 1.3 %	1.6 % - 2.4 %	2.4 % - 2.6 %
Expected life	5.3 - 6.0 years	5.0 - 6.0 years	5.8 - 5.8 years
Expected volatility (based on historical price)	61.2 % - 62.8 %	55.2 % - 61.5 %	6.2 % - 62.5 %

Stock Compensation Expense

The Company recorded $1.6 million, $1.7 million, and $2.3 million of stock compensation expense for the years ended June 30, 2012, 2011, and 2010, respectively. Stock based compensation is included under general and administrative expense in the consolidated statements of operations.

The Company's compensation policy is designed to provide the Company's directors with a portion of their annual Board compensation in the form of equity. The number of shares for each director award is subject to an annual maximum of 15,000 shares. The Company issued 75,000 shares during 2012 pursuant to this policy.

Note 8 - Earnings Per Share

The following table summarizes the computation of basic and diluted earnings per share:

	June 30, 2012	2011	2010
	(In thousands, except share and per share amounts)		
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)
Basic weighted-average shares outstanding	53,592,958	52,398,936	51,410,596
Add: dilutive effects of stock options and unvested stock grants [(1)]	448,269	—	—
Diluted weighted-average common shares outstanding	$54,041,227	$52,398,936	$51,410,596
Basic net loss per common share	$0.49	$(0.62)	$(0.03)
Diluted net loss per common share	$0.49	$(0.62)	$(0.03)

[(1)] There is no dilutive effect on earnings per share in periods with net losses.

Potentially dilutive securities excluded from the calculation of diluted shares outstanding include the following:

	June 30, 2012	2011	2010
Stock options	100,000	—	—
Non-vested restricted stock	—	104,167	208,334
Total potentially dilutive securities	100,000	104,167	208,334

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Note 9 - Segment and Geographic Data

The Company conducts its operations through two wholly owned subsidiaries, NP, which operates in the United States, and MPAL, which is primarily active in Australia. The following table presents segment and geographic data for years ended:

	June 30, 2012	2011	2010
	(In thousands)		
Revenues			
NP	$6,173	$3,804	$2,291
MPAL	7,533	12,775	25,908
Corporate	646	2,722	2,826
Inter-segment eliminations	(640)	(1,125)	(2,500)
Consolidated revenues	$13,712	$18,176	$28,525
Net income (loss)			
NP	$2,154	$(23)	$(55)
MPAL	24,192	(25,968)	7,569
Corporate	(5,416)	(6,429)	(263)
Inter-segment eliminations	5,568	(12)	(8,697)
Consolidated net (loss) income	$26,498	$(32,432)	$(1,446)
Assets			
NP	$10,833	$16,985	$5,427
MPAL	67,748	49,291	63,131
Corporate	59,099	83,323	90,345
Inter-segment eliminations	(45,106)	(78,025)	(68,197)
Consolidated assets	$92,574	$71,574	$90,706
Expenditures for additions to long lived assets			
NP	$(4,857)	$(2,095)	$(328)
MPAL	(4,575)	(1,679)	(2,209)
Corporate	(145)	(794)	(306)
Consolidated expenditures for long lived assets	$(9,577)	$(4,568)	$(2,843)

The following table summarizes other significant items for years ended:

	June 30, 2012	2011	2010
	(In thousands)		
Depletion, depreciation, amortization, and accretion			
NP	$819	$919	$448
MPAL	695	1,653	4,834
Corporate	230	318	146
Consolidated depletion, depreciation, amortization, and accretion	$1,744	$2,890	$5,428
Lease operating			
NP	$5,232	$2,227	$1,373
MPAL	7,665	6,270	8,585
Corporate	—	750	158
Consolidated lease operating	$12,897	$9,247	$10,116

	June 30, 2012	2011	2010
	(In thousands)		
Exploration			
NP	$1,495	$151	$—
MPAL	4,796	2,378	1,273
Corporate	—	325	—
Consolidated exploration	$6,291	$2,854	$1,273
Income tax benefit (expense)			
MPAL	$5,951	$(5,463)	$(2,076)
Corporate	—	322	(570)
Consolidated income tax benefit (expense)	$5,951	$(5,141)	$(2,646)

Note 10 - Commitments

Operating Leases. The following table summarizes the Company's future minimum rental commitments under non-cancelable operating leases, net of guaranteed sublease income, as of:

	June 30, 2012
	(In thousands)
Amounts payable in:	
2013	$97
2014	162
2015	262
2016	268
2017 and thereafter	363
Total	$1,152

Rental expenses for each of the years ended June 30, 2012, 2011, and 2010, were $0.6 million, $0.5 million, and $0.4 million, respectively.

Purchase obligations. Although the Company is committed to certain exploration and capital expenditures related to MPAL, some of these expenses may be farmed out to third parties. Amounts payable under these firm commitments for fiscal year 2013 were $5.4 million as of June 30, 2012.

Note 11 - Related Party Transactions

Transactions with Young Energy Prize S.A. ("YEP") and Related Entities

First Private Investment in a Public Entity ("First PIPE"). The Company entered into a Securities Purchase Agreement (the "First Purchase Agreement") to finalize the terms of the First PIPE, dated February 9, 2009, with its largest stockholder, YEP, under which the Company agreed to sell, and YEP agreed to purchase, 8,695,652 shares (the "Shares") of the Company's common stock, par value $0.01 per share (the "Common Stock") at a purchase price of $1.15 per share, or an aggregate of AUD $10.0 million. YEP is a Luxembourg corporation. Mr. Nikolay Bogachev, a director of the Company since July 2009, is the President and CEO of YEP as well as an equity owner of YEP.

The First Purchase Agreement was amended on April 3, 2009, and June 30, 2009. On July 9, 2009, the Company and YEP completed the issuance and sale of the Shares to YEP in accordance with the First PIPE. The Company received gross proceeds of AUD $10.0 million, which was used for acquisitions, general corporate, and working capital purposes. On July 9, 2009, the Company also executed and delivered to YEP a Warrant Agreement entitling YEP to purchase an additional 4,347,826 shares of the Company's Common Stock (the "Warrant Shares") at an exercise price of $1.20 per Warrant Share, subsequently reduced to $1.15 per share on July 30, 2009. The shares sold to YEP in the First PIPE and the Warrant Shares were not registered under the Securities Act or state securities laws and may not be resold in the United States in the absence of an effective registration statement filed with the U.S. Securities and Exchange Commission ("SEC") or an available exemption from the applicable federal and state registration requirements.

Initially, the Warrant Agreement contained anti-dilutive provisions that reduced the exercise price of the warrants based on certain trigger events such as the issuance of additional shares at a discount from the then current warrant exercise price. Since the provisions permitted the warrant holder to avoid bearing some of the risks and rewards normally associated with equity share ownership, the warrants were initially classified as liabilities and marked to market each reporting date with the change in value flowing through earnings. On March 11, 2010, YEP and the Company agreed to amend the Warrant Agreement to remove certain anti-dilution provisions. As a result, the Warrants were reclassified as equity and no revaluations were required subsequent to March 11, 2010. For the year ended June 30, 2010, non-cash charges of $4.3 million were recorded in the consolidated statement of income.

U.S. Federal Tax Withholdings. During the third quarter of fiscal year 2012, the Company identified a potential liability of approximately $2.0 million related to the Company's failure to make the required U.S. Federal tax withholding in the course of its initial acquisition of NP. In October 2009, Magellan acquired 83.5% of the membership interests in NP (the "Poplar Acquisition"), from the two majority owners of NP, White Bear LLC ("White Bear") and YEP I, SICAV-FES ("YEP I"). Both of these entities are affiliated with Mr. Bogachev, a Director of Magellan and a foreign national. Due to the status of YEP I as foreign entity and the members of White Bear being foreign nationals, Magellan was required to make U.S. Federal tax withholdings from the payments to or for the benefit of White Bear and YEP I. Of the $2.0 million liability, $1.3 million was estimated to relate to the interest sold by White Bear, $0.6 million to the interest sold by YEP I, and $0.1 million to Magellan's interest on late payment of the U.S. Federal tax withholdings.

Upon the filing of U.S. income tax returns in relation to the Poplar Acquisition and payment of corresponding income taxes by White Bear and YEP I, Magellan is deemed to be relieved of its liability for the U.S. Federal tax withholdings as well as related penalties and interest except for Magellan's interest on late payment of the U.S. Federal tax withholdings. With regards to White Bear, Magellan has confirmed that as of the date of this filing, Mr. Bogachev has filed his U.S. income tax return and paid taxes due on the Poplar Acquisition, which were estimated at $0.3 million. Magellan has agreed to pay Mr. Bogachev $0.3 million in additional compensation. Had Mr. Bogachev not filed and paid his tax return, Magellan's liability in relation to its U.S. Federal tax withholdings requirements was estimated at $1.3 million as of June 30, 2012. With regards to YEP I, Magellan continues to seek from YEP I or, because YEP I is a now defunct entity, from its successor entities, the filing of its U.S. income tax return.

As of June 30, 2012, we have recorded a total liability of $1.0 million under accrued and other liabilities in the consolidated balance sheets related to this matter. That amount is comprised of the $0.3 million payment to Mr. Bogachev, $0.6 million in withholdings, penalties, and interest related to YEP I, and $0.1 million related to Magellan's interest on late payment of the U.S. Federal tax withholdings. The effect on the consolidated statements of operations for the year ended June 30, 2012, is an expense of $0.9 million recorded under general and administrative expense and an interest expense of $0.1 million.

Based upon an evaluation of all relevant quantitative and qualitative factors, and after considering SEC Staff Accounting Bulletins Nos. 99 and 108, management believes that any amounts attributable to the years ending June 30, 2010, and 2011, and the impact of correcting such amounts in the year ending June 20, 2012, is not material to any of the Company's consolidated financial statements presented herein.

Second Private Investment in a Public Entity ("Second PIPE"). On August 5, 2010, the Company executed a Securities Purchase Agreement (the "Second Purchase Agreement"), an Investor's Agreement, and a Memorandum of Agreement to finalize the terms of its Second PIPE with YEP.

The Purchase Agreement involves the issuance and sale of up to 5.2 million new Shares to YEP and/or one or more of its affiliates in return for $3.00 per new share issued and sold for an aggregate purchase price of $15.6 million ("Investment Transaction"). Pursuant to the terms of the Second Purchase Agreement, the Company is required to use the proceeds from the Investment Transaction to close the Evans Shoal Transaction. Since the Amended Asset Sales Agreement has been terminated and MPAL has received back the additional $10.0 million deposit, the Investment Transaction has not closed. The Company and YEP subsequently terminated the Second Purchase Agreement.

Investment Agreement and Related Amendment. On February 11, 2011, the Company and YEP executed an Investment Agreement to document the terms of additional financing to be provided by YEP to the Company in order to facilitate the closing of the Evans Shoal Transaction. On February 17, 2011, the Company and YEP executed an amendment to the Investment Agreement in the form of a side letter ("Side Letter"). Under the Investment Agreement, YEP shall provide funding to the Company required for the completion of the Evans Shoal Transaction in the amount of approximately AUD $85.5 million, which shall include the proceeds of the $15.6 million provided by the Investment Transaction. The Investment Agreement states that the funding of the AUD $85.5 million by YEP is contingent upon the requirements and conditions of the Evans Shoal Agreement being satisfied or waived. The Company and YEP has terminated the Investment Agreement, as amended by the Side Letter.

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Other Related Party Transactions

The Company leased its prior Denver office space from an entity owned, in part, by J. Thomas Wilson, President and CEO of the Company and a member of the Company's Board of Directors. The total lease expense paid under this arrangement was $72 thousand for the fiscal years ended June 30, 2012, and 2011, and $52 thousand for the fiscal year ended June 30, 2010. Following the relocation of the Company's headquarters to Denver, Colorado, a lease agreement for new office space was entered into with an unrelated party in August 2012. Consulting services of $59 thousand, $100 thousand, and $36 thousand for the fiscal years ended 2012, 2011, and 2010 was paid to Mr. Wilson.

J. Robinson West, the Chairman of the Board of Directors of the Company, is also Chairman, Founder, and CEO of PFC Energy ("PFC"). PFC has served as a consultant for the Company on various Australian projects. As of June 30, 2012, there were no consulting arrangements between the Company and PFC in place or planned. The total consulting fees paid to PFC during the fiscal year ended June 30, 2012, was $64 thousand for work performed primarily in fiscal year 2011. As of June 30, 2011, an amount of $49 thousand remained unpaid for consulting fees related to fiscal 2011, which has since been paid. PFC was paid $0.4 million in fiscal year 2011, of which $0.2 million was expensed in fiscal year 2010.

See Note 2 for information related to transactions the Company entered into with NT and ER, effective September 1, 2011.

Note 12 - Subsequent Events

As of June 30, 2012, $38.6 million of the Company's cash and cash equivalents was held in several Australian banks in time deposit accounts that have terms of 90 days or less. As of September 24, 2012, the Company has repatriated $20.0 million of these Australian held funds to the U.S. The Company does not anticipate that U.S. Federal Income Tax will be owed on this amount, due to the expected utilization of foreign tax credits carried forward from June 30, 2012, and foreign tax credits expected to be generated during the fiscal year ending June 30, 2013 (see Note 6). The intended use for the repatriated monies is the funding of Magellan's U.S. based operations, including part of its drilling activity at Poplar.

On July 16, 2012, William H. Hastings resigned from the Board of Directors of Magellan. Pursuant to the terms and conditions of the Employment Agreement between Mr. Hastings and the Company dated February 3, 2009, as amended by the addendum thereto dated September 27, 2011, the Company is required to pay Mr. Hastings two years' severance compensation as a result of the Company's decision to discontinue his employment with the Company and Mr. Hastings' decision to resign from the Board of Directors.

On August 28, 2012, Stratex Oil & Gas Holdings, Inc. ("Stratex") announced an unsolicited proposal for the acquisition of each outstanding share of the Company's common stock for $0.65 in cash and one share of Stratex common stock, the closing price for which as reported by the OTCQB on August 27, 2012 was $1.65 per share. On September 10, 2012, the Company announced that its Board of Directors, after carefully considering the unsolicited proposal and consulting with its financial and legal advisors, had determined not to pursue the Stratex proposal. On September 12, 2012, the Company received a subpoena from the U.S. Securities and Exchange Commission (the "SEC") for the production of documents in connection with these announcements. On September 14, 2012, the Company received a letter from the Financial Industry Regulatory Authority ("FINRA") indicating that FINRA is conducting a review of trading in the Company's common stock surrounding the August 28, 2012 announcement by Stratex, and requesting information and documents from the Company in connection therewith. The Company is cooperating fully with the SEC and FINRA in these matters.

On September 24, 2012, the Company announced that its Board of Directors had approved a new stock repurchase program whereby the Company is authorized to repurchase up to a total of $2.0 million in shares of its common stock. This authorization supersedes the prior plan and will expire on August 21, 2014. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including compliance with securities laws. Stock repurchases may be funded with existing cash balances or internal cash flow. The stock repurchase program may be suspended or discontinued at any time.

Note 13 - Supplemental Oil and Gas Information (Unaudited)

Supplemental Oil and Gas Reserve Information

The Company relies upon a combination of internal technical staff and third party consulting arrangements for reserve estimation and review. The reserve information presented below is based on estimates of net proved reserves as of June 30, 2012, 2011, and 2010, and was prepared in accordance with guidelines established by the SEC.

In the United States, reserves estimates were prepared by the Company's Operations Manager, Blaine Spies, in 2012, and were audited by the Company's independent petroleum engineering firm, Allen & Crouch Petroleum Engineers ("A&C"), in

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2012, 2011, and 2010. A copy of the summary reserve audit report of A&C is provided as Exhibit 99.1 to this Annual Report on Form 10-K. A&C does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

In Australia, reserve estimates were prepared by the Ryder Scott Company ("RS"), an independent petroleum engineering firm, in 2012, and 2011. In 2010, reserve estimates were prepared by the RISC Pty Ltd ("RISCS"), an independent petroleum engineering firm. Reserve estimates were prepared in accordance with the Company's internal control procedures, which include the verification of input data used by RS and RISC, as well as management review and approval. A copy of the summary reserve report of RS is provided as Exhibit 99.2 to this Annual Report on Form 10-K. RS does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

Proved reserves are the estimated quantities of oil, gas, and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. All of the Company's estimated proved reserves are located in North America and Australia.

Analysis of Changes in Proved Reserves

The following table sets forth information regarding the Company's estimated proved oil and gas reserve quantities. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

	United States		Australia [1]		Total	
	Oil (Mbbls)	Gas (MMcf)	Oil (Mbbls)	Gas (MMcf)	Oil (Mbbls)	Gas (MMcf)
Proved Reserves:						
2009	—	—	996.0	3.3	996.0	3.3
Extensions and discoveries	6,963.0	—	—	—	6,963.0	—
Revision of previous estimates	(74.0)	—	(694.0)	1.6	(768.0)	1.6
Purchase of minerals in place	2,631.0	—	—	—	2,631.0	—
Sales of minerals in place	—	—	(205.0)	—	(205.0)	—
Production	(42.0)	—	(97.0)	(3.4)	(139.0)	(3.4)
2010	9,478.0	—	—	1.5	9,478.0	1.5
Extensions and discoveries	6.0	—	—	—	6.0	—
Revision of previous estimates	(404.0)	—	64.0	(0.2)	(340.0)	(0.2)
Purchase of minerals in place	178.0	—	—	—	178.0	—
Production	(68.0)	—	(64.0)	(0.9)	(132.0)	(0.9)
2011	9,190.0	—	—	0.4	9,190.0	0.4
Extensions and discoveries	186.4	—	—	—	186.4	—
Revision of previous estimates	(1,643.8)	—	—	6.0	(1,643.8)	6.0
Purchase of minerals in place	1,246.8	—	—	5.5	1,246.8	5.5
Production	(74.2)	—	—	(0.4)	(74.2)	(0.4)
2012	8,905.2	—	—	11.5	8,905.2	11.5

[1] The amount of proved reserves applicable to Australia gas reflects the amount of gas committed to specific contracts and is net of royalties.

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	United States		Australia [1]		Total	
	Oil (Mbbls)	Gas (MMcf)	Oil (Mbbls)	Gas (MMcf)	Oil (Mbbls)	Gas (MMcf)
Proved Developed Reserves:						
June 30, 2010	2,515.0	—	—	1.5	2,515.0	1.5
June 30, 2011	2,249.0	—	—	0.4	2,249.0	0.4
June 30, 2012	1,646.7	—	—	11.5	1,646.7	11.5
Proved Undeveloped Reserves:						
June 30, 2010	6,963.0	—	—	—	6,963.0	—
June 30, 2011	6,941.0	—	—	—	6,941.0	—
June 30, 2012	7,258.4	—	—	—	7,258.4	—

[1] The amount of proved reserves applicable to Australia gas reflects the amount of gas committed to specific contracts and is net of royalties.

Extensions and discoveries. Extensions and discoveries are additions to reserve amounts either by drilling a well to extend the limits of a known reservoir or by drilling a well in a reservoir that was not included in previous reserves estimates, respectively. During the year ended June 30, 2012, in the United States, there was one discovery well, EPU 117, drilled in the Amsden formation at Poplar, which added 186 Mbbls to our reserves total. During the year ended June 30, 2011, in the United States, there were minor extensions related to Poplar. During the year ended June 30, 2010, in the United States, there were 6,963 Mbbls of extensions recorded at Poplar as a result of petrophysical, geophysical, and petrographic data based on our current proved developed wells which identified certain locations as proved undeveloped reserves.

Revision of previous estimates. Revisions of estimates represent upward (downward) changes in previous estimates attributable to new information gained primarily from development activity, production history, and changes to the economic conditions present at the time of each estimate. During the year ended June 30, 2012, in the United States, there was a 1,644 Mbbls downward revision of estimates as a result of modifications to projected production profiles from new wells. During the same period in Australia, there was a 6.0 Bcf upward revision of gas estimates related to the signing of a new gas sales contract with Santos in May 2012. During the period ended June 30, 2011, in the United States, there was a 404 Mbbls downward revision of oil estimates. During the same period in Australia, there was a 64 Mbbls upward revision of oil estimates and a 0.2 Bcf downward revision of gas estimates. During the period ended June 30, 2010, in the United States, there was a 74 Mbbls downward revision of oil estimates. During the same period in Australia, there was a 694 Mbbls downward revision of oil estimates and a 1.6 Bcf upward revision of gas estimates.

Purchase of minerals in place. During the year ended June 30, 2012, in the United States, there were 1,247 Mbbls of purchases of minerals in place related to the Company's consolidation of its ownership in NP and Poplar in September 2011. During the same period in Australia, there were 5.5 Bcf of purchases of minerals in place related to the consolidation of Magellan's ownership in Palm Valley as part of the Santos SA in the Amadeus Basin completed in May 2012. These minerals in place have been recorded as proved reserves because they have been contracted for sale under the Santos Gas Contract. During the year ended June 30, 2011, there were 178 Mbbls of purchases of minerals in place related to the Company's acquisition of non-controlling working interests in the leases of Poplar. During the year ended June 30, 2010, there were 2,631 Mbbls of purchases of minerals in place related to the Company's majority acquisition of NP in October 2009 and the Company's acquisition of Hunter's working interests in the leases of Poplar in March 2010.

Sales of minerals in place. Sales of minerals in place during 2010 relate to the Cooper basin asset sales. There were no adjustments to reserves quantities relating to sales of minerals in place for the years ended June 30, 2012, and 2011.

Standardized Measure of Oil and Gas

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented. The "standardized measure" is the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs and future income tax expenses, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, and depreciation, depletion, and amortization or tax, and are discounted using an annual discount rate of 10% to reflect timing of future cash flows.

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The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices, or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Prices. All prices used in calculation of our reserves are based upon a twelve month unweighted arithmetic average of the first day of the month price for the period July 2011 through June 2012, unless prices were defined by contractual arrangements. Prices are adjusted for local differentials and gravity and, as required by the SEC, held constant for the life of the projects (i.e., no escalation). The resulting prices used for proved reserves for the year ended June 30, 2012 are:

	United States	Australia
Year ended June 30, 2012		
Oil	$84.94	NA
Gas	NA	$4.64

Costs. Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Income taxes. Future income tax expenses are calculated by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

Discount. The present value of future net cash flows from the Company's proved reserves is calculated using a 10% annual discount rate. This rate is not necessarily the same as that used to calculate the current market value of our estimated oil and natural gas reserves.

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The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves:

	United States	Australia	Total
	(In thousands)		
Fiscal year ended June 30,			
2012			
Future cash inflows	$756,405	$53,296	$809,701
Future production costs	(291,212)	(34,729)	(325,941)
Future development costs	(34,416)	(4,107)	(38,523)
Future income tax expense	(152,314)	(3,667)	(155,981)
Future net cash flows	278,463	10,793	289,256
10% annual discount	(156,967)	(2,214)	(159,181)
Standardized measures of discounted future net cash flows	$121,496	$8,579	$130,075
2011			
Future cash inflows	$734,592	$972	$735,564
Future production costs	(303,005)	(700)	(303,705)
Future development costs	(28,849)	—	(28,849)
Future income tax expense	(155,701)	—	(155,701)
Future net cash flows	247,037	272	247,309
10% annual discount	(137,021)	(8)	(137,029)
Standardized measures of discounted future net cash flows	$110,016	$264	$110,280
2010			
Future cash inflows	$627,842	$3,031	$630,873
Future production costs	(251,335)	(1,870)	(253,205)
Future development costs	(27,293)	(1,780)	(29,073)
Future income tax expense	(132,843)	(297)	(133,140)
Future net cash flows	216,371	(916)	215,455
10% annual discount	(131,163)	1,062	(130,101)
Standardized measures of discounted future net cash flows	$85,208	$146	$85,354

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A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	United States	Australia	Total
	(In thousands)		
Standardized measure of discounted future net cash flows for Fiscal year ended June 30,			
2009	$—	$20,055	$20,055
Extensions and discoveries	115,092	—	115,092
Acquisitions of reserves	29,656	—	29,656
Revisions of previous quantity estimates	(8,258)	1,850	(6,408)
Divestiture of reserves	—	(11,687)	(11,687)
Sales and transfers of oil and gas produced	(1,064)	(12,299)	(13,363)
Accretion of discount	1,725	—	1,725
Net change in income taxes	(53,722)	2,227	(51,495)
Net change in timing and other	1,779	—	1,779
2010	85,208	146	85,354
Net change in prices and production costs	24,899	38	24,937
Extensions and discoveries	117	—	117
Acquisitions of reserves	3,486	—	3,486
Revisions of previous quantity estimates	(7,041)	1,094	(5,947)
Changes in estimated future development costs	(798)	536	(262)
Sales and transfers of oil and gas produced	(2,406)	(1,940)	(4,346)
Accretion of discount	13,893	41	13,934
Net change in income taxes	(16,125)	297	(15,828)
Net change in timing and other	8,783	52	8,835
2011	110,016	264	110,280
Net change in prices and production costs	18,517	—	18,517
Extensions and discoveries	6,785	—	6,785
Acquisitions of reserves	26,584	4,872	31,456
Revisions of previous quantity estimates (1)	(37,846)	6,144	(31,702)
Changes in estimated future development costs	(2,275)	(555)	(2,830)
Sales and transfers of oil and gas produced	(941)	(264)	(1,205)
Previously estimated development cost incurred during the period	5,841	—	5,841
Accretion of discount (2)	—	—	—
Net change in income taxes	(1,657)	(1,576)	(3,233)
Net change in timing and other	(3,528)	(306)	(3,834)
2012	$121,496	$8,579	$130,075

(1) The downward revision of previous quantity estimates of 1,644 Mbbls resulted from a reduced well count which was impacted by higher operating costs.

(2) For the year ended June 30, 2012, Magellan assumed no benefit from the accretion of the beginning of year value of its proved oil reserves in the United States. Accretion, with respect to measuring the changes in the standardized measure of reserves values, represents the value benefit of being closer in time, relative to the prior year's standardized measure, to future cash flows in the reserves projections. During the year ended June 30, 2012, Magellan did not develop its United States proved oil reserves in accordance with its reserve plan as of June 30, 2011, and instead postponed its reserves development plan by one year. Therefore, the benefit of accretion of last year's reserves should not factor into the value of the current standardized measure.

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Note 14 - Oil and Gas Activities (Unaudited)
Costs Incurred in Oil and Gas Producing Activities
Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	United States	Australia	United Kingdom	Total
	(In thousands)			
Fiscal year ended June 30,				
2012				
Proved	$1,606	$5,634	$—	$7,240
Unproved	945	3,787	—	4,732
Exploration Costs	2,192	1	5	2,198
Development Costs	2,779	—	—	2,779
Total, including asset retirement obligation	$7,522	$9,422	$5	$16,949
2011				
Proved	$380	$—	$—	$380
Unproved	150	—	—	150
Exploration Costs	762	976	3,023	4,761
Development Costs	1,971	4	—	1,975
Total, including asset retirement obligation	$3,263	$980	$3,023	$7,266
2010				
Proved	$13,456	$—	$—	$13,456
Exploration Costs	—	714	1,127	1,841
Development Costs	314	1,428	—	1,742
Total, including asset retirement obligation	$13,770	$2,142	$1,127	$17,039

The net changes in capitalized costs that are currently not being depleted pending the determination of proved reserves can be summarized as follows:

	United States	Australia	United Kingdom	Total
	(In thousands)			
Fiscal year ended June 30,				
2012				
Balance at beginning of year	$2,411	$415	$5,259	$8,085
Additions to capitalized costs	4,631	3,973	1,369	9,973
Assets sold or held for sale	(150)	—	—	(150)
Reclassified to producing properties	(3,772)	—	—	(3,772)
Charged to expense	(1,297)	—	(2,106)	(3,403)
Exchange adjustment	—	—	102	102
Balance at end of year	$1,823	$4,388	$4,624	$10,835

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	United States	Australia	United Kingdom	Total
	(In thousands)			
2011				
Balance at beginning of year	$314	$415	$3,576	$4,305
Additions to capitalized costs	2,406	—	1,703	4,109
Assets sold or held for sale	—	—	—	—
Reclassified to producing properties	(277)	—	—	(277)
Charged to expense	(32)	—	36	4
Exchange adjustment	—	—	(56)	(56)
Balance at end of year	$2,411	$415	$5,259	$8,085
2010				
Balance at beginning of year	$—	$3,487	$3,154	$6,641
Additions to capitalized costs	314	—	608	922
Assets sold or held for sale	—	(3,072)	—	(3,072)
Reclassified to producing properties	—	—	—	—
Charged to expense	—	—	(232)	(232)
Exchange adjustment	—	—	46	46
Balance at end of year	$314	$415	$3,576	$4,305

At June 30, 2012, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

Note 15 - Quarterly Financial Data (Unaudited)

The following table summarizes the unaudited quarterly financial data, including income before income taxes, net income, and net income per common share for the years ended 2012 and 2011.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	June 30, 2012
	(In thousands, except per share data)				
Year ended June 30, 2012					
Total operating revenues	$3,735	$3,202	$4,805	$1,970	$13,712
Total operating expenses (income)	$2,883	$8,076	$9,367	$(26,388)	$(6,062)
Income (loss) before income taxes	$1,123	$(4,755)	$(4,590)	$28,754	$20,532
Net income (loss) attributable to Magellan Petroleum Corporation	$940	$(4,557)	$(4,590)	$34,705	$26,498
Net income (loss) per basic common share outstanding	$0.02	$(0.08)	$(0.09)	$0.64	$0.49
Net income (loss) per diluted common share outstanding	$0.02	$(0.08)	$(0.09)	$0.64	$0.49

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	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	June 30, 2011
	(In thousands, except per share data)				
Year ended June 30, 2011					
Total operating revenues	$3,699	$4,461	$4,867	$5,149	$18,176
Total operating expenses	$7,658	$8,158	$4,947	$25,632	$46,395
(Loss) income before income taxes	$(3,713)	$(3,476)	$111	$(20,218)	$(27,296)
Net loss attributable to Magellan Petroleum Corporation	$(3,376)	$(2,099)	$(84)	$(26,873)	$(32,432)
Net loss per basic common share outstanding	$(0.06)	$(0.04)	*	$(0.51)	$(0.62)
Net loss per diluted common share outstanding	$(0.06)	$(0.04)	*	$(0.51)	$(0.62)

(*) Not meaningful

During the fourth quarter of fiscal year 2012, Magellan, through its wholly owned subsidiary MPAL, completed the Santos SA (see Note 2) and became the sole owner of the Palm Valley Interests and of the Dingo Interests, while Santos became the sole owner of the Mereenie Interests. The transaction resulted in a gain on sale of assets in the amount of $36.2 million.

Note 16 - Reclassification

Certain reclassifications have been made to the prior period consolidated financial statements to conform them to the current year format. Magellan believes this change improves presentation of our financial statements by conforming them to industry-specific norms. This reclassification had no effect on previously reported results.

The table below provides a summary of the reclassifications related to the consolidated balance sheet for the comparative period presented.

	June 30, 2011
	(In thousands)
CONSOLIDATED BALANCE SHEET	
As reported previously:	
Oil and gas properties (successful efforts method)	$138,577
Land, buildings, and equipment	4,089
Field equipment	6,390
Less accumulated depletion, depreciation, and amortization	(119,903)
Net property and equipment	$29,153
As currently reported:	
Proved oil and gas properties	$136,094
Less accumulated depletion, depreciation, and amortization	(115,917)
Unproved oil and gas properties	3,368
Wells in progress	4,315
Land, buildings, and equipment, net of accumulated depreciation	1,293
Net property and equipment	$29,153

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The table below provides a summary of the reclassifications related to the consolidated statements of operations for the comparative periods presented.

	June 30, 2011	2010
	(In thousands)	
CONSOLIDATED STATEMENTS OF OPERATIONS		
As reported previously:		
Salaries and employee benefits	$5,079	$4,816
Depletion, depreciation, and amortization	2,326	4,680
Auditing, accounting, and legal services	2,595	1,948
Accretion expense	564	748
Shareholder communications	396	551
Other administrative expenses	7,286	6,031
Foreign transaction loss	951	677
Total	$19,197	$19,451
As currently reported:		
Depletion, depreciation, amortization, and accretion	$2,890	$5,428
General and administrative	16,307	14,023
Total	$19,197	$19,451

ITEM 9: CHANGES IN, AND DISAGREEMENTS WITH, ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A: CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including resource constraints and judgments about the expected benefits of control alternatives relative to their costs, assumptions about the likelihood of future events, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our

Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective.

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

Management assessed the effectiveness of the Company's internal control over financial reporting as of June 30, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework

Based on our assessment and these criteria, we believe that internal control over financial reporting is effective as of June 30, 2012.

This annual report does not include an attestation report of the company's registered public accounting firm regarding internal control over financial reporting. Our internal controls over financial reporting were not subject to attestation by the Company's registered public accounting firm pursuant to rules of the SEC that permit the Company to provide only management's report in this annual report.

Description of Material Weaknesses at June 30, 2011

The Company did not maintain effective internal controls over the preparation of the consolidated statement of cash flows and the review of third party expert work for significant complex and/or non-routine accounting issues:

1. An error in the Company's unaudited condensed consolidated statement of cash flows was identified as of March 31, 2011. Certain foreign currency exchange losses were improperly excluded from the reconciliation of our net loss to cash flows from operations. In addition, certain other errors were made in the preparation of the consolidated statement of cash flows for the period ended June 30, 2011. These errors, if taken individually, would not be considered material, however, on an aggregate basis were considered a material weakness.
2. The Company's internal control procedures over the review of the work provided by third party accounting experts were not effective.

Remediation Actions Relating to the Material Weaknesses

Beginning in the fiscal year 2012, the Company initiated a process to improve its internal control over financial reporting which included regular reports issued to the Audit Committee and Board of Directors as to the progress of the remediation.

1. The improvement of processes surrounding the statement of cash flows included the following steps:

- An improved process of consolidating the financial statements has been implemented, including a more efficient process to communicate, receive, and consolidate information from international locations.
- The Company has augmented its financial reporting and technical accounting resources to enable a more detailed and rigorous review of the cash flow statement in compliance with GAAP.

2. The improvement of the review process of work provided by third party accounting experts included the following steps:

- The Company has hired additional accounting and finance resources with increased technical abilities, reducing reliance on and use of third party accounting experts.
- An enhanced process to review complex accounting matters and the work provided by third party expert has been implemented among the senior accounting staff of the Company.

We believe the measures described above remediated the material weaknesses we identified in 2011 and have strengthened our internal controls over financial reporting. We identified no such material weakness that existed at June 30, 2012. We are committed to continually improving our internal control processes and will diligently and vigorously review our

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financial reporting controls and procedures. As we continue to evaluate and work to improve our internal controls over financial reporting, we may determine that additional measures are necessary to address control deficiencies. Moreover, we may decide to modify certain of the remediation measures described above.

CHANGE IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Other than described above, there have not been any other changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of the Company's fiscal year ended June 30, 2012, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B: OTHER INFORMATION

Not applicable.

PART III

Pursuant to General Instruction G(3), the information called for by Items 10, (except for information concerning the executive officers of the Company) 11, 12, 13, and 14 is hereby incorporated by reference to the Company’s definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012. Certain information concerning the executive officers of the Company is included under Item 10: Directors, Executive Officers, and Corporate Governance of this report.

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The following table sets forth the names, ages, and positions held by the Company’s executive officers. The ages of our executive officers are listed as of September 24, 2012.

Name	Age	Office Held	Length of Service as Officer
J. Thomas Wilson	60	President and Chief Executive Officer	Since September 2011
Antoine J. Lafargue	38	VP - Chief Financial Officer and Treasurer	Since July 2010
C. Mark Brannum	46	VP - General Counsel and Secretary	Since September 2012

For further information regarding the named executive officers, see the Company’s definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012.

ITEM 11: EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012.

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012.

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ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012.

ITEM 14: PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from June 30, 2012.

PART IV

ITEM 15: EXHIBITS AND FINCANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the consolidated financial statements and notes thereto.

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(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

EXHIBIT NUMBER	DESCRIPTION
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Ehrhardt Keefe Steiner & Hottman PC
23.2*	Consent of Deloitte & Touche LLP
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS***	XBRL Instance Document
101.SCH***	XBRL Taxonomy Extension Schema Document
101.CAL***	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF***	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB***	XBRL Taxonomy Extension Label Linkbase Document
101.PRE***	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith.
**	Furnished herewith.
***	To be furnished by amendment. Users of this data to be submitted electronically are advised pursuant to Rule 406T of Regulation S-T that this interactive data file will not be deemed filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, will not be deemed filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise will not be subject to liability under these sections.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MAGELLAN PETROLEUM CORPORATION
(Registrant)

By: /s/ J. Thomas Wilson
John Thomas Wilson, President and Chief Executive Officer
(as Principal Executive Officer)

By: /s/ Antoine J. Lafargue
Antoine J. Lafargue, Vice President - Chief Financial Officer and Treasurer
(as Principal Financial and Accounting Officer)

Date: September 28, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

/s/ J. Thomas Wilson John Thomas Wilson, President and Chief Executive Officer, and Director	Date: September 28, 2012
/s/ Antoine J. Lafargue Antoine J. Lafargue, Vice President - Chief Financial Officer, and Treasurer	Date: September 28, 2012
/s/ Donald V. Basso Donald V. Basso, Director	Date: September 28, 2012
/s/ Nikolay Bogachev Nikolay Bogachev, Director	Date: September 28, 2012
/s/ Walter McCann Walter McCann, Director	Date: September 28, 2012
/s/ Robert J. Mollah Robert J. Mollah, Director	Date: September 28, 2012
/s/ Ronald P. Pettirossi Ronald P. Pettirossi, Director	Date: September 28, 2012
/s/ J. Robinson West J. Robinson West, Director	Date: September 28, 2012

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INDEX TO EXHIBITS

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23.2*	Consent of Deloitte & Touche LLP
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS***	XBRL Instance Document
101.SCH***	XBRL Taxonomy Extension Schema Document
101.CAL***	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF***	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB***	XBRL Taxonomy Extension Label Linkbase Document
101.PRE***	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith.
**	Furnished herewith.
***	To be furnished by amendment. Users of this data to be submitted electronically are advised pursuant to Rule 406T of Regulation S-T that this interactive data file will not be deemed filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, will not be deemed filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise will not be subject to liability under these sections.