UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended June 30, 2011

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.)
7 Custom House Street, 3rd Floor, Portland ME	**04101**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code
(207) 619-8500

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 $.01 per share	NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act

Title of Class

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 ☑

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 ☑

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 ☑ 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 ☐ 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 ☐	Accelerated filer ☑	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	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 ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant at the $2.87 closing price on December 31, 2010 (the last business day of the most recently completed second quarter) was $120,355,442.

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 $.01 per share, 52,552,852 shares outstanding as of September 1, 2011

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement related to the Annual Meeting of Stockholders for the fiscal year ended June 30, 2011 are incorporated by reference in Part III of this Form 10-K to the extent stated herein.

Table of Contents

TABLE OF CONTENTS

Unless otherwise indicated, all dollar figures set forth herein are in United States currency. Amounts expressed in Australian currency are indicated as ("AUD", "AUS", "A$"). The exchange rate at September 1, 2011 was approximately (AUD) $1.00 which equaled U.S. $1.07.

[Table of Contents](#)

PART I

Items 1 and 2: ***Business and Properties.***

GENERAL OVERVIEW

Magellan Petroleum Corporation (the “Company” or “Magellan” or “MPC” or “we” or “us”) is engaged in the sale of oil and gas and the exploration for and development of oil and gas reserves. MPC was incorporated in 1957 under the laws of Panama and was reorganized under the laws of Delaware in 1967. At June 30, 2011, MPC has three reporting segments: (1) our 100.00% equity interest in its subsidiary, Magellan Petroleum Australia Limited (“MPAL”); (2) an 83.5% controlling member interest in Nautilus Poplar, LLC (“Nautilus”), based in Denver, Colorado and (3) MPC the parent company that owns directly a 28.3% working interest in the East Poplar Unit and Northwest Poplar Field (collectively, the “Poplar Field”) in Montana.

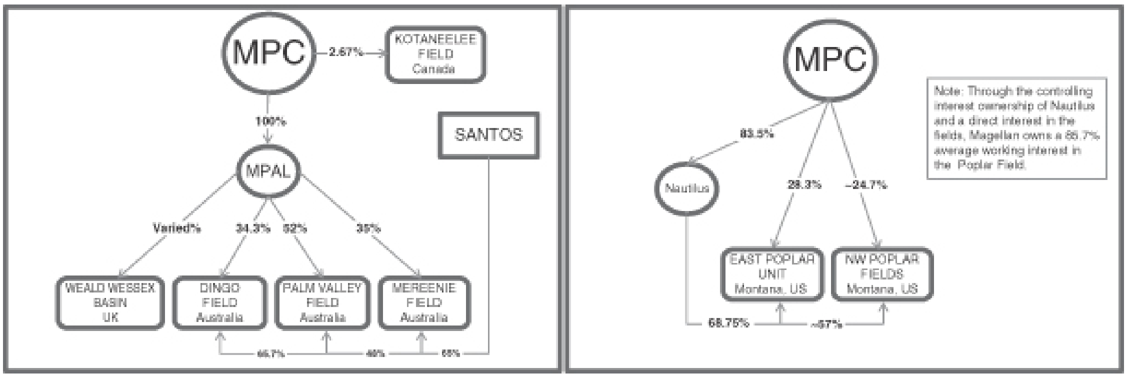
MPAL’s major assets are two petroleum production leases covering the Mereenie oil and gas field (35% working interest), one petroleum production lease covering the Palm Valley gas field (52% working interest), one retention license for the Dingo Field (34.3% working interest) and thirteen licenses in the United Kingdom, four of which are operated by MPAL. The Mereenie, Palm Valley, and Dingo fields are located in the Amadeus Basin in the Northern Territory of Australia. Santos Ltd (“Santos”), a publicly owned Australian company, owns a 65% interest in the Mereenie field, a 48% interest in the Palm Valley field, and 65.7% interest in the Dingo field and is the operator of the Mereenie and Dingo fields. MPAL is operator of the Palm Valley field.

On December 4, 2009, the Company announced the sale of all its interests in the Cooper and Maryborough Basins in Australia. The Company subsequently entered into sales agreements to affect the sale of those interests including for the sale of its Authority to Prospect (“ATP”) 613P, ATPA 674P, ATP 732P and ATPA 733P interests which we completed during the year end June 30, 2011. These assets were disposed of because they are non-core to our strategies. See Note 10 for further discussion.

MPC acquired its 83.5% controlling interest in Nautilus in October 2009. Nautilus, based in Denver, Colorado, operates and holds a 68.75% interest in the East Poplar Unit and varied interests averaging 57% in the Northwest Poplar Field. MPC owns directly a 28.3% working interest in the Poplar Field. The Poplar Field is comprised of 23,000 combined licensed acres and has an estimated 700 to 800 million barrels of oil in place in the Charles Formation with 52 million barrels recovered to date. The Poplar Field is also being developed for Bakken shale as well as other shallow and deep oil and gas reservoirs. On a consolidated basis, MPC through Nautilus and directly owned an average 85.7% working interest in the Poplar Fields in Montana as of June 30, 2011. See Note 13 for further discussion.

MPC ORGANIZATION CHARTS

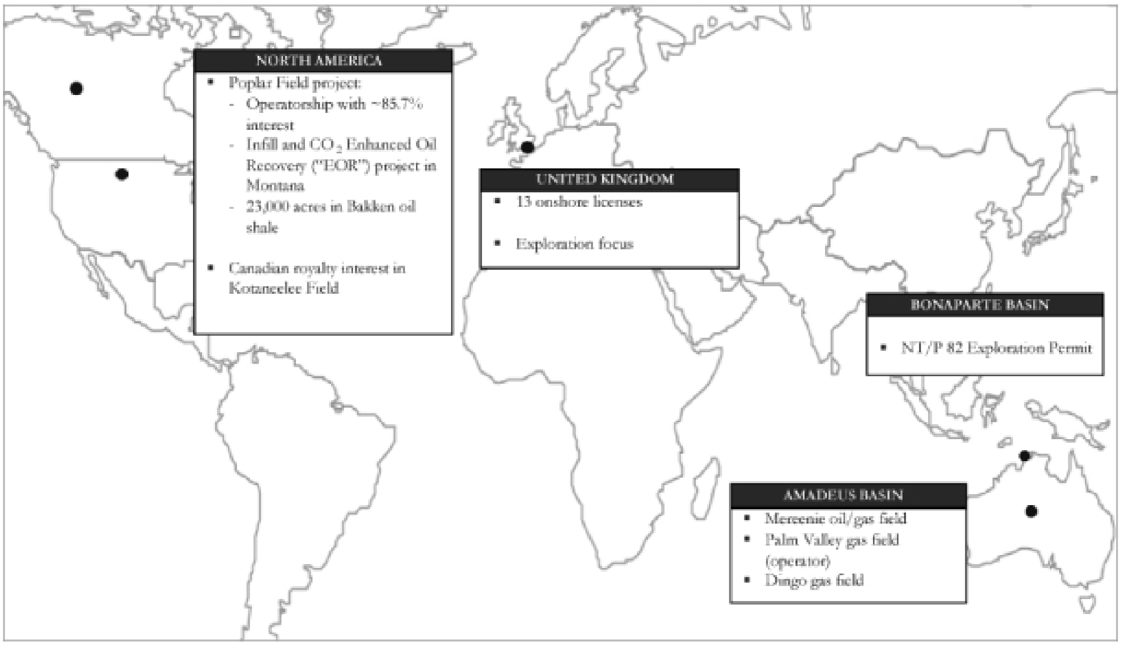
As of June 30, 2011:



[Table of Contents](#)

OIL AND GAS PROPERTIES AND ACTIVITIES

The following map is a summary of oil and gas properties in which the Company has an interest. The Company is committed to certain exploration and development expenditures, some of which may be farmed out to third parties.



AUSTRALIA

Mereenie Oil and Gas Field

MPAL (35%) and Santos (65%), the operator (together known as the "Mereenie Producers"), own the Mereenie field which is located in the Amadeus Basin of the Northern Territory. At June 30, 2011, MPAL's share of the Mereenie field proved developed oil reserves was zero. Under the revised rules of the U.S. Securities and Exchange Commission ("SEC"), proved reserves of natural gas cannot be booked for Mereenie until a natural gas sales agreement is completed. Probable developed oil and gas reserves have been booked at Mereenie.

During fiscal 2011, MPAL's share of oil and condensate sales was approximately 64 MBbls, which is subject to net overriding royalties aggregating 4.06% and the statutory government royalty of 10%.

Prior to June 2009, the oil was transported by means of a 167-mile eight-inch crude oil pipeline flowing eastbound from the field to Brewer Estate, southwest of Alice Springs. The oil was then shipped south approximately 950 miles by road to the Port Bonython Export Terminal at Whyalla, South Australia for sale. Beginning with June 2009, service on the pipeline was suspended and the line was idled pending future evaluation. Oil production began direct road transport from the field to the Port Bonython Export Terminal. The cost of transporting the oil to the terminal is borne by the Mereenie Producers. The petroleum leases covering the Mereenie field expire in November 2023.

The Mereenie Producers were contracted until September 5, 2010 to supply gas on a reasonable endeavors basis to the Power and Water Corporation ("PWC") for use in the Northern Territory. After September 5, 2010, natural gas volumes continued to be produced, were processed for condensate and then cycled back for reinjection into the field. See "Gas Supply Contracts" below.

Table of Contents

On September 14, 2011, Magellan Petroleum (N.T.) Pty Ltd ("Magellan NT"), a wholly owned subsidiary of MPAL, entered into a Sale Agreement ("Santos SA") with Santos QNT Pty Ltd ("Santos QNT") and Santos Limited ("Santos Entities"). The Santos SA provides for the transfer of Magellan NT's 35% interest in the Mereenie oil and gas field to the Santos Entities and the transfer of the Santos entities 47.977% interest in the Palm Valley gas field and the 65.6635% interest in the Dingo gas field to Magellan NT subject to the satisfaction of certain conditions.

The cash consideration payable to Magellan NT is A$25 million plus a bonus amount based on Mereenie future production levels.

Upon completion of the Santos SA, Magellan NT entered into a Gas Supply and Purchase Agreement (the "GSPA") with the Santos Entities on September 14, 2011, and provides for the sale by Magellan NT to the Santos Entities of a total contract gas quantity of 25.65PJ over the anticipated 17 year term of the GSPA.

Palm Valley Gas Field

As of June 30, 2011, MPAL has a 52.023% interest in, and is the operator of, the Palm Valley gas field which is also located in the Amadeus Basin of the Northern Territory. Santos, the operator of the Mereenie field, owns the remaining 47.977% interest in the Palm Valley Field. MPAL and Santos ("Palm Valley Producers") provide Palm Valley gas to meet a supply contract with PWC. See "Gas Supply Contracts" below. Pursuant to the same SEC rules noted for Mereenie above, basing proved developed bookings on gas sales agreement volumes, MPAL's share of the Palm Valley proved developed reserves was .43 Bcf at June 30, 2011 and is based upon gas contract amounts. During fiscal 2011, MPAL's share of gas sales was .86 Bcf which is subject to a 10% statutory government royalty and net overriding royalties aggregating 7.31%. Under the current gas sales agreement, PWC funds the cost of additions and modifications to the gas delivery system under the gas supply agreement. The petroleum lease covering the Palm Valley Field expires in November 2024.

Magellan NT has entered into the Santos SA to receive all of the Santos Entities' interest in the Palm Valley and Dingo fields with effect July 1, 2011, as described above. Upon completion of the Santos Agreement MPAL will own 100% of the Palm Valley and Dingo gas fields and will have 25.65PJ of gas contracted under the GSPA with the Santos Entities. (See Note 20)

Dingo Gas Field

MPAL has a 34.34% interest in the Dingo gas field which is held under Retention License No. 2 in the Amadeus Basin in the Northern Territory. No market has emerged for gas volumes that have been discovered in the Dingo gas field. MPAL's share of potential production from this permit area is subject to a 10% statutory government royalty and overriding royalties aggregating 4.81%. The license was renewed for a further five year term and expires in February 2014.

Magellan NT has entered into the Santos SA to receive all of the Santos Entities' interest in the Palm Valley and Dingo fields with effect July 1, 2011, as described above. Upon completion of the Santos Agreement MPAL will own 100% of the Palm Valley and Dingo gas fields and will have 25.65PJ of gas contracted under the GSPA with the Santos Entities. (See Note 20)

Gas Supply Contracts

In 1983, the Palm Valley Producers commenced the sale of gas to Alice Springs under a 1981 agreement. That agreement terminated in June 2008. In 1985, the Palm Valley Producers and Mereenie Producers signed agreements for the sale of gas to PWC, through its wholly-owned company Gasgo Pty Ltd ("Gasgo"), for use in PWC's Darwin electricity generating station and at a number of other generating stations in the Northern Territory. The price of gas under the Palm Valley gas contract was adjusted quarterly to reflect changes in the Australian Consumer Price Index. The gas was delivered into the 922-mile Amadeus Basin gas pipeline which was built by an Australian consortium in 1987. Since 1985, there were several additional contracts for the sale of Mereenie gas, the latest being the Mereenie Sales Agreement No. 4 in June 2006 for the supply of an additional

4.4 Bcf of gas to be supplied prior to December 31, 2008. The principal Mereenie contracts and supply obligations under the various agreements expired in January and June 2009, and September 2010. The Palm Valley gas contract expires in January 2012.

MPAL's major customer, PWC, contracted with Eni Australia in 2006 for the supply of PWC's Northern Territory gas demand requirement for twenty-five years, commencing January 2009. Eni Australia expected to commence sales from its Blacktip field offshore of the Northern Territory in January 2009; however, the Blacktip development encountered significant delays and only commenced partial production in September 2009 with full production not achieved until February 2010. The Mereenie Producers continued to supply PWC's gas requirements on a reasonable endeavors basis to supplement Blacktip gas sales until early February 2010.

Upon completion of the Santos SA, as described above, Magellan NT entered into a Gas Supply and Purchase Agreement (the "GSPA") with the Santos Entities on September 14, 2011, and provides for the sale by Magellan NT to the Santos Entities of a total contract gas quantity of 25.65PJ over the 17 year term of the GSPA.

The term of the GSPA shall commence on the later of Completion under the Sale Agreement, the first delivery of gas under a Concession GSPA or January 16, 2012 (when the existing gas sales agreement for the Palm Valley Gas Field expires) and will expire if the total contract quantity is reached before the expiry of 17 years.

As MPAL was not able to sell its uncontracted gas reserves for the fiscal year 2011, its revenues have declined in 2011. Palm Valley gas sales were approximately $1.8 million (net of royalties) or 100% of total gas sales for the year ended June 30, 2011, $2.1 million (net of royalties) or 15% of total gas sales for the year ended June 30, 2010, and $2.2 million (net of royalties) or 15% of total gas sales for the year ended June 30, 2009. There were no gas sales from Mereenie for the year ended June 30, 2011. There were $11.6 million of gas sales from Mereenie (net of royalties) or 85% of total sales for the year ended June 30, 2010, and $12.4 million (net of royalties) or 85% of total gas sales for the year ended June 30, 2009.

At June 30, 2011, MPAL's commitment to supply gas under the Palm Valley contract was as follows:

Period	Bcf
Less than one year	0.43
Total	0.43

Evans Shoal Gas Field

Evans Shoal is a large, yet to be developed natural gas field with an estimated contingent gas resource in excess of 6.6 Tcf, including CO_2 gas content, in the Bonaparte Basin, offshore Northern Australia. The field was discovered in 1988 and lies in a range of water depths from very shallow to more than 300 feet.

MPAL entered into an agreement with Santos on March 25, 2010 ("Asset Sales Deed"), to purchase Santos' 40% interest in the Evans Shoal natural gas field (NT/P48) ("Evans Shoal Transaction"). Under the Asset Sales Deed, the Company agreed to pay Santos a time-staged cash consideration equal to (AUD) $100 million for its interest in the Evans Shoal field which included a (AUD) $15 million deposit. The Company also agreed to pay additional contingent payments to Santos of (AUD) $50 million upon a favorable partner vote on any final investment decision to develop the Evans Shoal field and a further (AUD) $50 million upon first stabilized gas production from the field. Closing and completion of the purchase was subject to regulatory and other approvals. The Australian Foreign Investment Review Board indicated it had 'no objection' to the acquisition of Santos' interest by MPAL.

The Asset Sales Deed was amended by the January 31, 2011 Deed of Variation ("Amended Asset Sales Deed") which extended the closing date of the Evans Shoal Transaction through to May 31, 2011 in exchange for (1) MPAL's release to Santos of the initial (AUD) $15 million escrow deposit payment made towards the closing price (“First Escrow Amount”) and (2) an additional (AUD) $10 million escrow account deposit towards the closing price (“Second Escrow Amount”). While the Amended Asset Sales Deed provided that the payment of the Second Escrow Amount would be made in accordance with the terms of the Amended Asset Sales Deed which provided certain defined circumstances under which MPAL was entitled to reimbursement of the deposit, the Amended Asset Sales Deed re-classified the First Escrow Amount as non-refundable.

On July 21, 2011, Santos and MPAL executed a Release Agreement to (1) terminate the Amended Asset Sales Deed and (2) resolve all outstanding issues relating to the Amended Asset Sales Deed. Under the Release Agreement, MPAL received back the Second Escrow Deposit, plus all interest accrued on that deposit from the date of deposit to the date of release and the parties agreed to mutually release each other from all claims arising out of the Asset Sales Deed and the Evans Shoal Transaction. As a result, the A$15 million deposit was written off.

In connection with the unwinding of the Evans Shoal Transaction, the Company and Santos executed agreements to transfer their interests in the Amadeus licenses with a resulting ownership interest by the Company of 100% of the Palm Valley and Dingo gas fields. (See Note 20)

LICENSES AND PERMITS

MPAL has interests directly and indirectly in the following permits. Permit holders are generally required to carry out agreed work and expenditure programs. (See Note 16)

Permit	Ownership Interest	Expiration Date	Location
Petroleum Lease No. 4 and No. 5 (Mereenie) (Amadeus Basin)	35%	November 17, 2023	Northern Territory, Australia
Petroleum Lease No. 3 (Palm Valley) (Amadeus Basin)	52.023%	November 7, 2024	Northern Territory, Australia
Retention License No. 2 (Dingo) (Amadeus Basin)	34.3365%	February 16, 2014	Northern Territory, Australia
NT/P82 (Bonaparte Basin)	100%	May 12, 2016	Offshore Northern Territory, Australia
PEDL 125 (Weald Basin)	40%	June 30, 2012	United Kingdom
PEDL 126 (Weald Basin)	40%	June 30, 2014	United Kingdom
PEDL 135 (Weald Basin)	100%	September 30, 2012	United Kingdom
PEDL 137 (Weald Basin)	100%	September 30, 2012	United Kingdom
PEDL 155 (Weald Basin)	40%	September 30, 2015	United Kingdom
PEDL 231 (Weald Basin)	50%	June 30, 2014	United Kingdom
PEDL 232 (Weald Basin)	50%	June 30, 2014	United Kingdom
PEDL 234 (Weald Basin)	50%	June 30, 2014	United Kingdom
PEDL 240 (Wessex Basins)	23%	June 30, 2014	United Kingdom
PEDL 242 (Weald Basin)	100%	June 30, 2014	United Kingdom
PEDL 243 (Weald Basin)	50%	June 30, 2014	United Kingdom
PEDL 246 (Weald Basin)	100%	June 30, 2014	United Kingdom
PEDL 256 (Weald Basin)	40%	April 30, 2015	United Kingdom

Petroleum permits issued by the Northern Territory of Australia 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 produced. Rental payments may be offset against the royalty paid. The term of a lease is 21 years, and leases may be renewed for successive terms of 21 years each.

Petroleum Exploration and Development Licenses issued by the Government of the United Kingdom are subject to the Petroleum Act. Licensees have the exclusive right to produce petroleum from the land subject to payment of a rental. The term of the license is 31 years.

Bonaparte Basin

The Commonwealth – Northern Territory Offshore Petroleum Joint Authority granted Exploration Permit for Petroleum NT/P82 to the Company (100% interest) over Area NT09-1. Area NT09-1 was offered for competitive bid under the Australian Government 2009 Release of Offshore Petroleum Exploration Areas. The exploration permit was granted on May 13, 2010 for a six year term. The committed work program under the permit during the first three years of the term involves the reprocessing of existing seismic data, the acquisition of additional 2D and 3D seismic data and the interpretation of the combined seismic database. NT/P82 lies to the south and southeast of the Evans Shoal gas field within the Bonaparte Basin.

Magellan undertook the reprocessing of 2,061 miles of existing 2D seismic data during the first year of the permit and planning has commenced to undertake the acquisition of 62 miles of 2D and 46 square miles of 3D seismic data during the second permit year. Acquisition of the seismic surveys is planned for the first quarter of 2012. At June 30, 2011, MPAL's share of the work obligations committed for the NT/P82 permit was $1,798,000.

Maryborough Basin

MPAL held a 100% interest in exploration permit ATP 613P in the Maryborough Basin in Queensland, Australia. MPAL (100%) also has applications pending for permits ATP 674P and ATP 733P which are adjacent to ATP 613P. The Company was granted the previously excluded areas of ATP 613P in September 2010 and is waiting on the grant of ATP 674P and ATP 733P by the Queensland Government.

In May 2006, MPAL entered into a farm-out agreement in relation to ATP 613P, ATPA 674P and ATPA 733P with Eureka Petroleum, under which that company funded the drilling of two coal seam gas exploration wells in 2007 which intersected multiple thin coal seams. Eureka Petroleum has agreed to undertake a staged evaluation of the area to earn a 75% interest in any petroleum lease granted. MPAL retained a 25% interest and is carried by Eureka Petroleum through any development to the grant of a petroleum lease.

On January 16, 2010, the Company entered into an asset sale agreement with Adelaide Energy to sell all of its ownership interests in the three petroleum exploration permits ATP 613P, ATP 733P and ATP 674P. The transaction with Adelaide Energy closed on November 30, 2010 following the grant of the ATP 613P excluded areas. ATP 674P and ATP 733P will be transferred to Adelaide Energy following their grant.

UNITED KINGDOM

PEDL 125 & PEDL 126 (Markwells-1)

Effective July 1, 2003, MPAL acquired two Petroleum Exploration and Development Licenses ("PEDL"), PEDL 125 (40%) in Hampshire and PEDL 126 (40%) in West Sussex, in the Weald Basin of southern England; each granted for an initial exploration term of six years. The terms of both PEDL's were extended by the Government; PEDL 126 will expire in June 2015 and PEDL 125 in June 2012. A PEDL will be extended past the end of its 11-year exploration term for a further 20-year production term if a development plan for production is approved by the Government.

The South Downs National Park was established by the Government in April 2011 over a 636 square mile area in southern England including parts of PEDL 125 and PEDL 126. Any petroleum development with the South Downs Nation Park must comply with the park's Planning Policy. The Department of Energy supports the exploration and production of onshore oil and gas in line with its stated aim to maximize the economic recovery of UK's oil and gas reserves, taking full account of environmental, social and economic objectives.

The Company participated in the Markwells Wood-1 exploration well in PEDL 126, which spudded in November 2010. Northern Petroleum is operator of the PEDL 126 joint venture. Markwells Wood-1 well targeted the eastward extension of the Horndean oil field which is currently producing from the Great Oolite Formation. Assessment of the well logs confirmed that the entire Great Oolite reservoir sequence in Markwells Wood-1 is oil-bearing above the Horndean field oil-water contact of 4,446 ft sub-sea level.

The presence of mobile ('live') oil was observed in 30 feet of core in the upper section of the Great Oolite. Analysis of the logs indicate the well, which was deviated at an inclination of approximately 56 degrees through the Great Oolite, penetrated a gross hydrocarbon bearing interval of 275 ft with a calculated net reservoir of 192 ft with an average porosity of 13-14%; a typical porosity value for this reservoir in the nearby fields in the same formation. Northern Petroleum started operations for an extended well test of the Markwells Wood oil discovery in West Sussex, with the arrival of a workover rig on September 6, 2011. The test will enable the joint venture partners to evaluate the potential and scheme for future development of the Markwells Wood oil accumulation.

At June 30, 2011, MPAL's share of the work obligations committed for the PEDL 125 and PEDL 126 licenses totaled $1,805,000.

PEDL 153, PEDL 154, PEDL 155 & PEDL 256

Effective October 1, 2004, MPAL acquired three licenses, PEDL 153 (33.3%), PEDL 154 (50%) and PEDL 155 (40%), in the Weald-Wessex Basins in southern England, each granted for an initial exploration term of six years. Each license has a drill or drop obligation at the end of its initial exploration term. The drilling plans for the Havant-1 well in PEDL 155 are under consideration. The initial exploration term of PEDL 155 was extended for a further four years and will expire on September 30, 2015. PEDL 153 and PEDL 154 terminated on September 30, 2010. The U.K. Company, Egdon Resources, will fund part of MPAL's share of the PEDL 155 drilling and exploration costs to acquire a 10% interest in the license.

During fiscal year 2001, MPAL acquired an interest in exploration license PEDL 099 of the Portsdown area of Hampshire in southern England in the Weald Basin. The license (MPAL 40%) expired in September 2008. The former PEDL 099 licensees made an out-of-round application for a license over the northeast portion of the former PEDL 099 area which is adjacent to the Havant Prospect in PEDL 155. PEDL 256 was granted to MPAL (40% interest) and its joint venture partners for a period of six years with effect from May 2009 with a drill or drop obligation at the end of the initial exploration term. PEDL 256 expires in April 2015.

At June 30, 2011, MPAL's share of the work obligations committed for the PEDL 155 & PEDL 256 licenses was $1,429,000.

PEDL 231, PEDL 232, PEDL 234 & PEDL 243

Effective July 1, 2008, MPAL (50%) and its joint venture partner, Celtique Energie, were granted interests in PEDL 231, PEDL 232, PEDL 234 and PEDL 243 located in the central Weald Basin of southern England. Each license has a drill or drop obligation at the end of its initial exploration term and expires in June 2014. Celtique Energie, operator of the four joint ventures, will acquire 109 miles of 2D seismic data in PEDL 231, PEDL 234 and PEDL 243 during the fall of 2011 to more closely define drilling prospects identified from the existing seismic data, which will fulfill the firm work obligations under the licenses. At June 30, 2011, MPAL's share of the work obligations committed for the PEDL 231, PEDL 232, PEDL 234 & PEDL 243 licenses was $1,456,000.

PEDL 135, PEDL 137, PEDL 242 & PEDL 246

Effective October 1, 2004, MPAL was granted 100% interest in PEDL 135, and PEDL 137 in the Weald Basin in southern England for a term of six years. Effective July 1, 2008, MPAL was granted 100% interest in PEDL 242 and PEDL 246 located adjacent to the other licenses; each with a six year initial term. The initial exploration term of each of PEDL 135 and PEDL 137 has been extended to September 30, 2012. PEDL 136 expired on September 30, 2010. Each license has a drill or drop obligation at the end of its initial term. MPAL has undertaken a program of seismic data purchase, reprocessing and interpretation and has identified three drilling prospects. At June 30, 2011, MPAL's share of the work obligations committed for the PEDL 135, PEDL 137, PEDL 242 and PEDL 246 licenses was $149,000.

PEDL 098 & PEDL 240

During fiscal year 2001, MPAL acquired an interest in an exploration license in southern England in the Weald-Wessex Basins. The license, PEDL 098 (22.5%), on the Isle of Wight was granted for a term of six years. The Sandhills-2 well, drilled in PEDL 098 during 2005, encountered a heavily biodegraded remnant oil column and was plugged and abandoned. PEDL 098 was surrendered in May 2011 towards the end of its 11-year term. Effective July 1, 2008, MPAL and its joint venture partners were granted PEDL 240 (22.5%) adjacent to PEDL 098 for an initial exploration term of six years. The license has a drill or drop obligation at the end of its initial exploration term. An exploration well has to be drilled within the first six years of the initial term in order for the license to be extended into the next five-year license term, as was the case for PEDL 098. At June 30, 2011, MPAL's share of the work obligations committed for the PEDL was $38,000.

UNITED STATES

East Poplar Unit and Northwest Poplar Oil Fields

On October 15, 2009, MPC completed the purchase of an 83.5% controlling interest in Nautilus. Nautilus, based in Denver, Colorado, owns a majority interest in and operates the Poplar Field in Roosevelt County, Montana. The controlling interest in Nautilus was purchased from White Bear, LLC and ECP Fund, SICAV-FIS (formerly, YEP I, SICAV- FIS) entities affiliated with Nikolay Bogachev and J. Thomas Wilson, two directors of the Company.

MPC also completed a consolidation of interests in the Poplar Field by purchasing a 25.05% average working interest from Hunter Energy, LLC and a 3.25% average working interest from Nautilus Technical Group, LLC in March 2010. On a consolidated basis, MPC, through Nautilus and directly, owned an average 85.7% working interest in the Poplar Fields in Montana as of June 30, 2011.

The Poplar Field was discovered and developed in 1954 by Murphy Oil Company. The Field, with 23,000 combined licensed acres, has an estimated 700-800 million barrels of original oil in-place with 52 million barrels recovered to-date (largely from just the Charles formation) or approximately 7% of in-place reserves. Typical recovery factors in other fields with like characteristics are 20% to 30%. Magellan (through Nautilus) has embarked on an active development program utilizing both infill and tertiary enhanced oil recovery programs shown to be successful and productive in adjacent, similar fields in both the U.S. and in nearby Canada. Although certain contingencies must materialize, attractive upside potential is seen in the three producing oil horizons in the Mississippian Charles formation, up to 23,000 acres of Bakken shale, and both shallow and deep gas plays.

For the year end June 30, 2011, the Poplar Field produced approximately 86 MBbls with approximately 35 active wells producing from the Charles Formation. During June 30, 2011, MPC's share of oil sales was approximately 68 MBbls, which is net of royalties and overriding royalties averaging 21%. At June 30, 2011, MPC's share of the Poplar Field proved oil reserves was approximately 9,190 MBbls.

The oil is transported by truck to a lease automatic custody transfer ("LACT") facility in Reserve, MT where it enters the Enbridge Oil Pipeline to Clearbrook, MN. The East Poplar Unit and Northwest Poplar Field leases are held by production.

On September 2, 2011, the Company signed and closed a Purchase and Sale Agreement with the owners of Nautilus Technical Group LLC, ("Nautilus Technical"), and Eastern Rider LLC, ("Eastern Rider"), (collectively the “Sellers”), resulting in the Company owning 100% of Nautilus Poplar and, directly or indirectly through Nautilus, a 100% working interest in the Poplar Field, aside from certain working interest owners in the Northwest Poplar fields. (See Note 20)

On September 7, 2011 the Company and VAALCO Energy (USA) Inc. (“VAALCO”) signed a definitive Lease Purchase and Sale Agreement (the “VAALCO LPSA”). VAALCO also agreed to drill three wells, at its sole expense as operator, to the Bakken formation and to formations below the Bakken (the “Deep Intervals”) in Poplar Field. Upon completion of three (3) new wells in the Deep Intervals of the Poplar Field, VAALCO will earn a 65% working interest in the Deep Intervals within the Poplar Field. One well will be spud on or before June 1, 2012 and the second and third will be spud on or before December 31, 2012. One well will be drilled horizontally to test the Bakken Formation, one well will be drilled vertically to test the Red River Formation, and a third will be targeted at VAALCO’s discretion.

The Company will retain a 35% working interest in the Deep Intervals and will continue to hold its current interest in all formations above the Bakken formation, including the currently producing Charles and Tyler formations where all Poplar proved and probable reserves are located.

The Company has initiated a program in late summer 2011 to undertake seven recompletions along with the completion of the East Poplar Unit (“EPU”) 119 drilled last fall into the Charles Formation. Magellan also plans to drill one shallow natural gas well in fall of 2011 to evaluate significant reservoir pressure differentials seen in the shallow gas horizon during the drilling of the EPU119 well.

A second drilling program, including up to three new infill wells in the Charles Formation, is planned for the fall of 2011. Drilling will be based upon the results from the recompletion program with the objective of increased production resulting in increased cash generation amid high oil price netbacks.

Given the complexity of the Poplar reservoir, the Company has completed the first steps of a reservoir engineering study for the Charles Formation. Further work is being conducted to manage and monitor water influx, determine new high potential drilling sites, and to determine the merit of an infill program.

RESERVES

Detailed information regarding reserves, costs of oil and gas activities, capitalized costs, discounted future net cash flows and results of operations is disclosed in Note 19.

A summary of our estimated proved, probable and possible reserves as of June 30, 2011 are set forth in the table below. The table shows reserves on an Mboe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio.

Summary of Oil and Gas Reserves as of June 30, 2011 Fiscal Year End
Based on Average Fiscal-Year Prices

	Total			Australia		United States		All other Foreign Geographic areas	
Proved Reserves:	**Oil (MBbls)**	**Gas (Bcf)**	**Mboe**	**Oil (MBbls)**	**Gas (Bcf)**	**Oil (MBbls)**	**Gas (Bcf)**	**Oil (MBbls)**	**Gas (Bcf)**
Proved Developed Producing (PDP)	1,127	0.43	1,199	—	0.43	1,127	—	—	—
Proved Developed Not Producing (PDNP)	1,122	—	1,122	—	—	1,122	—	—	—
Proved Undeveloped (PUD)	6,941	—	6,941	—	—	6,941	—	—	—
Total Proved	9,190	0.43	9,262	—	0.43	9,190	—	—	—
Probable undeveloped	1,824	—	1,824	—	—	1,824	—	—	—
Total reserves	11,014	0.43	11,086	—	0.43	11,014	—	—	—

Information regarding changes in estimated reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 19.

Proved Undeveloped Reserves

MPC first recorded these Proved Undeveloped reserves related to the Poplar Field at June 30, 2010.

In the United States, Magellan commenced a drilling and development program in the Poplar Field with the EPU 119 that reached a depth of 7,137 feet on October 18, 2010. Well results to-date, while under further evaluation, yielded a broad stack of hydrocarbon-bearing formations from 692 feet all the way to total vertical depth of 7,137 feet. A Charles Formation core (the current producing formation) was completed and is currently under analysis. A Bakken and Three Forks core was also successfully obtained and analyzed, where it was found that the Bakken is over pressured and mature, with oil and gas saturation, and substantial fracturing and fair to good porosity. The EPU119 well was targeting possible reserve volumes in the Nisku Formation and failed to produce commercially viable quantities of oil. However, EPU 119 did encounter hydrocarbons up hole of the Nisku Formation in the Charles Formation as seen on the well logs and in the core. Completion work is currently planned for EPU 119 in the fall of 2011. Other than the EPU 119, the Company did not drill any new wells at the Poplar Field during this reporting period. The Company has a drilling program planned for the fall of 2011 to drill up to three new wells in the Charles Formation targeting proven undeveloped reserves. Since the program is relatively new to the Company, there is no recent experience of converting proved undeveloped reserves to proved developed reserves.

In Australia, the Company has no recent experience of converting possible reserves to probable reserves and probable reserves to proved reserves. In Australia, our possible and probable oil reserves relate to the Mereenie Field in Northern Territory, where there has not been any drilling since 2004.

Preparation of Oil and Gas Reserve Information

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

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 also 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.

Possible reserves. Estimates of possible developed and undeveloped reserves are also inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also 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 possible reserve quantities, and when deterministic methods are used to estimate possible reserve quantities, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geo-science and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geo-science and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and we believe that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

PRODUCTION VOLUMES, PRICES AND COSTS

MPC's production volumes, net of royalties, average sales prices and average production costs for oil and gas during the three years ended June 30, 2011, 2010, 2009 are as follows (data for Canada has not been included since MPC is in a carried interest position and the data is not material):

	Production Volumes			Average Sales Prices		Average Production Costs	
	Oil (MBls)	Gas Bcf	Total(2) MBOE	Oil (per bbl)	Gas (per mcf)	Oil (per bbl)	Gas (per mcf)
2011							
Australia (AUD)	55	0.71	173	$99.67	$ 2.28	$ 93.40	$ 2.22
United States (1) (3)	68	—	68	77.96	—	34.58	—
U.K.	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—
Total	123	0.71	241				
2010							
Australia (AUD)	97	3.43	669	82.19	5.07	30.92	1.86
United States	42	—	42	67.88	—	36.43	—
U.K.	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—
Total	139	3.43	711				
2009							
Australia (AUD)	153	5.18	1,016	91.21	3.54	26.72	0.99
U.K.	—	—	—	—		—	—
Other	—	—	—	—	—	—	—
Total	153	5.18	1,016				

(1) Net Production by field was 51 MBbls for EPU and 17 MBbls for Northwest Poplar Field.
(2) Natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio.
(3) Includes 6 MBbls attributable to a consolidated subsidiary in which there was, as of June 30, 20111, an 16.5% non-controlling interest. (See Note 20)

Table of Contents

PRODUCTIVE WELLS

Productive wells at June 30, 2011 were as follows:

	Production Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Australia	16.0	5.6	10.0	4.2
United States	35.0	30.0	—	—
Other Foreign Countries	—	—	3.0	0.1
	51.0	35.6	13.0	4.3

ACREAGE

The following table summarizes gross and net developed and undeveloped acreage by geographic area at June 30, 2011. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty or overriding royalty is excluded.

	Developed Acreage		Undeveloped		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Australia						
Mereenie	31,567	11,048	38,482	13,469	70,049	24,517
Palm Valley	41,644	21,664	116,288	60,497	157,932	82,161
Dingo	—	—	116,139	39,878	116,139	39,878
Offshore	—	—	1,556,647	1,556,647	1,556,647	1,556,647
United States						
Poplar Field	22,893	18,693	648	542	23,541	19,235
All Other						
U.K — Weald / Wessex Basin	—	—	449,737	270,253	449,737	270,253
Total	**96,104**	**51,405**	**2,277,941**	**1,941,286**	**2,374,045**	**1,992,691**

Of the total undeveloped acreage (2.3 million gross, 1.9 million net), as of June 30, 2011, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 4% in 2012, 0% in 2013 and 11% in 2014.

DRILLING ACTIVITY

There were two wells in process at June 30, 2011.

The Company has a 40% interest in the Markwells Wood-1 exploration well in PEDL 126, which spudded in November 2010. Northern Petroleum is operator of the PEDL 126 joint venture. Markwells Wood-1 well targeted the eastward extension of the Horndean oil field which is currently producing from the Great Oolite Formation. Assessment of the well logs confirmed that the entire Great Oolite reservoir sequence in Markwells Wood-1 is oil-bearing above the Horndean field oil-water contact of 4,446 ft sub-sea level. Northern Petroleum started operations for an extended well test of the Markwells Wood oil discovery, with the arrival of a workover rig on September 6, 2011. The test will enable the joint venture partners to evaluate the potential and scheme for future development of the Markwells Wood oil accumulation.

Magellan commenced a drilling and development program in the Poplar Field, with the EPU 119 that reached a depth of 7,137 feet on October 18, 2010. Well results to-date, while under further evaluation, yielded a broad stack of hydrocarbon-bearing formations from 692 feet all the way to current depth. The deepest target, the Nisku Formation, proved to be non-commercial and the well will be recompleted up hole in the Charles. Completion work is currently planned for EPU 119 in the fall of 2011.

Table of Contents

Productive and dry net wells drilled during the following years (data concerning Canada is insignificant):

Year ended June 30	Total				Australia				United States				All Other Foreign Geographic Areas			
	Exploration		Development		Exploration		Development		Exploration		Development		Exploration		Development	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2011	0.4	—	1.0	—	—	—	—	—	—	—	1.0	—	0.4	—	—	—
2010	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2009	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

MARKETING ACTIVITIES AND CUSTOMERS

Customers

Although MPAL's producing oil and gas properties are located in a remote area in central Australia, the completion in January 1987 of the Amadeus Basin to Darwin gas pipeline has provided access to and expanded the potential market for MPAL's gas production.

Natural Gas Production

MPAL's customer, PWC, contracted with Eni Australia in 2006 for the supply of PWC's Northern Territory gas demand requirement for twenty five years, commencing January 2009. Eni Australia expected to commence sales from its Blacktip field offshore of the Northern Territory in January 2009; however, the Blacktip development encountered significant delays and only commenced partial production in September 2009 with full production not achieved until February 2010. The Mereenie Producers continued to supply PWC's gas requirements on a reasonable endeavors basis to supplement Blacktip gas sales until early February, 2010. The last Mereenie gas sales contract terminated in September, 2010. As MPAL was not able to sell its uncontracted gas, its revenues have declined in 2011.

However, upon completion of the Santos SA, Magellan NT entered into a Gas Supply and Purchase Agreement (the "GSPA") with the Santos Entities on September 14, 2011, that provides for the sale by Magellan NT to the Santos Entities of a total contract gas quantity of 25.65PJ over the anticipated 17 year term of the GSPA.

Oil Production

MPAL — Presently all of the crude oil and condensate production from Mereenie is being shipped and sold through the Port Bonython Export Terminal, Whyalla, South Australia. Oil sales during fiscal 2011 were 66.6% to the Santos group of companies, 20.2% to the Beach Petroleum group of companies and 13.2% to Origin Energy Resources.

Nautilus — Presently all of the oil production from the Poplar Field is being trucked to a terminal in Reserve, MT and sold to Plains Marketing, LP.

CURRENT MARKET CONDITIONS AND COMPETITION

Competitive Conditions in the Business

The exploration for and production of oil and gas are highly competitive operations. The ability to exploit a discovery of oil or gas is dependent upon such considerations as the ability to finance development costs and the availability of equipment. The success of exploitation is also the ability to avoid or minimize the effect of engineering and construction delays and difficulties. The Company also must compete with major oil and gas companies which have substantially greater resources.

Furthermore, various forms of energy legislation which have been or may be proposed in the countries in which the Company holds interests may substantially affect competitive conditions. However, it is not possible to predict the nature of any such legislation which may ultimately be adopted or its effects upon the future operations of the Company.

Seasonality of Business

Although the Company's business is not seasonal, the demand for oil and especially gas is subject to seasonal fluctuations in the weather.

SEGMENT INFORMATION

The Company is engaged in only one industry, namely, oil and gas exploration, development, production and sale. The Company conducts such business through its three operating segments: MPC, its 100% equity interest in its subsidiary, MPAL, and its 83.5% controlling member interest in Nautilus, as of June 30, 2011. See Note 15.

EMPLOYEES

Number of Persons Employed by Company.

As of fiscal year ended June 30, 2011 the Company had 42 total employees. MPC had 8 employees and Nautilus had 12 employees in the United States. At that date, MPAL had 22 employees in Australia.

REGULATORY MATTERS, ENVIRONMENTAL AND ADDITIONAL FACTORS AFFECTING BUSINESS

Environmental Regulation.

The Company is subject to the environmental laws and regulations of the jurisdictions in which it carries on its business, and existing or future laws and regulations could have a significant impact on the exploration for and development of natural resources by the Company. However, to date, the Company has not been required to spend any material amounts for environmental control facilities. The federal and state governments in Australia strictly monitor compliance with these laws but compliance therewith has not had any adverse impact on the Company's operations or its financial resources. We are subject to stringent and complex U.S. and Canadian federal, state, provincial and local environmental laws, regulations and permits and international environmental conventions, including those relating to the generation, storage, handling, use, disposal, movement and remediation of natural gas, natural gas liquids, oil and other hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife protection; the storage, use and treatment of water; and the placement, operation and reclamation of wells. These requirements are a significant consideration for us as our operations involve the generation, storage, handling, use, disposal, movement and remediation of natural gas, natural gas liquids, oil and other hazardous or regulated materials and the emission and discharge of such materials to the environment. If we violate these requirements, or fail to obtain and maintain the necessary permits, we could be fined or otherwise sanctioned, which sanctions could include the imposition of fines and penalties and orders enjoining future operations. Pursuant to such laws, regulations and permits, we have made and expect to continue to make capital and other compliance expenditures.

At fiscal year ended June 30, 2011, the Company had accrued approximately $11.4 million for asset retirement obligations for the Mereenie, Palm Valley, Dingo and Poplar Field (See Note 5).

Financial Information Relating to Foreign and Domestic Operations.

See Note 15 and Note 19.

Risks Attendant to Foreign Operations.

Many of the properties in which the Company has interests are located outside the United States and are subject to certain risks involved in the ownership and development of such foreign property interests. These risks include but are not limited to those of: nationalization; expropriation; confiscatory taxation; changes in foreign exchange controls; currency revaluations; price controls or excessive royalties; export sales restrictions; limitations on the transfer of interests in exploration licenses; and other laws and regulations which may adversely affect the Company's properties, such as those providing for conservation, proration, curtailment, cessation, or other limitations of controls on the production of or exploration for hydrocarbons. Thus, an investment in the Company represents a speculation with risks in addition to those inherent in domestic petroleum exploratory ventures.

Since 1992, there has been an ongoing controversy regarding the Aborigines and the ownership of their traditional lands. There has been legislation aimed at resolving this controversy. The Company does not believe that this issue will have a material adverse impact on MPAL's properties.

AVAILABLE INFORMATION

Information regarding the Company, including corporate governance policies, code of ethics and charters for the committees of the board of directors can be found on our Internet website at http://www.magellanpetroleum.com and copies of these documents are available to stockholders, without charge, upon request to Jeffrey Tounge, Corporate Secretary, Magellan Petroleum Corporation, 7 Custom House Street, 3rd Floor, Portland, Maine 04101 (tel: (207) 619-8500). The information contained in our website is not intended to be incorporated into this Form 10-K. In addition, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are made available free of charge on our Internet website on the same day that we electronically file such material with, or furnish it to, the SEC. Information filed with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. These filings are also available to the public from commercial document retrieval services and at the Internet website maintained by the SEC at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

Item 1A. ***Risk Factors***

Set forth below and elsewhere in this Annual Report on Form 10-K are the risks and uncertainties that should be considered in evaluating the Company's common stock and that could cause the actual future results of the Company to differ from those expressed or implied in the forward-looking statements contained in this Annual Report and in other public statements the Company makes. Additionally, because of the following risks and uncertainties, as well as other variables affecting the Company's operating results, the Company's past financial performance should not be considered an indicator of future performance.

The principal oil and gas properties owned by MPAL, MPC and Nautilus could stop producing oil and gas.

MPAL's Palm Valley field and Nautilus' Poplar Field could stop producing oil and gas or there could be a material decrease in production levels at the fields. Since these are the three principal revenue producing properties of Magellan, any decline in production levels at these properties could cause Magellan's revenues to decline. Any such adverse impact on the revenues and cash flows being received by Magellan could restrict our ability to explore and develop oil and gas properties in the future and cause our stock price to decline.

MPAL's production history depended upon long-term gas supply contracts, one of which was not renewed, and MPAL's business has been adversely impacted.

MPAL's financial performance and cash flows have historically been dependent upon its Palm Valley and Mereenie supply contracts to sell gas produced at these fields to MPAL's former major customer, Gasgo, a subsidiary of PWC of the Northern Territory. Gasgo has contracted with Eni Australia for the supply of PWC's Northern Territory gas demand requirement for twenty five years. Eni Australia, commenced sales in

September 2009, is to supply the gas from its Blacktip field offshore of the Northern Territory. The Mereenie Producers continued to supply PWC's gas demand on a reasonable endeavors basis to supplement Blacktip gas sales as required until September 5, 2010. The last Mereenie gas sales contract terminated in September, 2010. As MPAL was not able to sell its uncontracted gas, its revenues have declined in 2011.

In fiscal year 2010, we completed an acquisition of a 83.5% controlling member interest in Nautilus and may make acquisitions or investments in new oil and gas reserves, operating businesses or assets that involve additional risks, which could disrupt our business or harm our financial condition or results of operations.

As part of our business strategy, in October 2009, we acquired a controlling interest in Nautilus. We expect to continue to make acquisitions of companies that possess oil and gas reserves or other businesses or assets that are complementary to our growth strategy. Such acquisitions or investments involve a number of risks, including:

- assimilating operations and new personnel may be unexpectedly difficult;
- management's attention may be diverted from other business concerns;
- we may enter markets in which we have limited or no direct experience;
- we may lose key employees of an acquired business;
- we may not realize the value of the acquired assets relative to the price paid; and
- despite our due diligence efforts, we may not succeed at quality control or other customer issues.

These factors could have a material adverse effect on our business, financial condition and operating results. 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.

Our plans to drill for oil and gas at fields located in the U.S. and U.K. may not result in successful discoveries of oil and gas.

During fiscal year 2012, the Markwells Wood-1 well, in the Weald Basin United Kingdom in which we hold interests, is currently being production tested to recover oil and gas in commercially viable quantities. On October 18, 2010, Magellan commenced a drilling and development program in Poplar Field, with the EPU 119. Completion work is currently planned in the fall of 2011. If these drilling projects are not successful, no revenues will be achieved from the drilling projects and our results of operations would be adversely affected.

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

Our plans for drilling in the U.K. and U.S. 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.

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.

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 the officers and key employees of MPC, Nautilus, and MPAL. 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.

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 MPC.

The properties in which Magellan has interests located outside the United States are subject to certain risks related to the indirect ownership and development of foreign properties, including government expropriation, adverse changes in currency values and foreign exchange controls, foreign taxes, nationalization and other laws and regulations, any of which may adversely affect the Company's properties. Although there are currently no exchange controls on the payment of dividends to the Company by MPAL, such payments could be restricted by Australian foreign exchange controls, if implemented.

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 and our outstanding warrants and shareholders may be adversely affected by the issuance of those shares.

As of June 30, 2011, there were 4,347,826 warrants outstanding and 5,200,000 stock options outstanding of which 3,258,332 are fully vested and exercisable. As of that date, there were also 1,270,000 options available for future grants under our 1998 Stock Incentive Plan as amended in December of 2010 ("Plan"). If all of these options and warrants, which total 10,817,826 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 1, 2011 the Company's shares closed at $1.55 per share. If the Company shares were to be delisted from trading on the Nasdaq Capital Market, then most likely the shares would be traded on the Electronic Bulletin Board, or OTC-BB. The delisting of the Company's shares from NASDAQ could adversely impact the liquidity and value of the Company's shares.

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

The Company and its affiliates had approximately 42 total employees as of June 30, 2011. Despite our increase in employment relative to prior years, 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 will also 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 create 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.

RISKS RELATED TO THE OIL AND GAS INDUSTRY

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

Our revenues, operating results, profitability, 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, natural gas, methane gas and other fuels 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;
- changes in the supply and demand for such fuels;
- 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;
- weather conditions (i.e. hurricanes), including effects on prices and supplies in worldwide energy markets;
- the competitive position of each such fuel as a source of energy as compared to other energy sources; and
- the effect of governmental regulation 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, then up slightly to $76 per barrel in September 2010 and $82 per barrel in August 2011, while natural gas prices have declined from over $13 per mcf to approximately $4 per mcf over the same period.

Sustained declines in oil and gas prices would not only reduce our revenues, but 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 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 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 Magellan.

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 oil and gas exploration and production operations are subject to numerous environmental laws, compliance with which may be extremely costly.

Our operations are subject to environmental laws and regulations in the various countries in which they are conducted. Such laws and regulations frequently require completion of a costly environmental impact assessment and government review process prior to commencing exploratory and/or development activities. In addition, such environmental laws and regulations may restrict, prohibit, or impose significant liability in connection with spills, releases, or emissions of various substances produced in association with fuel exploration and development.

We can provide no assurance that we will be able to comply with applicable environmental laws and regulations or that those laws, regulations or administrative policies or practices will not be changed by the various governmental entities. The cost of compliance with current laws and regulations or changes in environmental laws and regulations could require significant expenditures. Moreover, if we breach any governing laws or regulations, we may be compelled to pay significant fines, penalties, or other payments. Costs associated with environmental compliance or noncompliance may have a material adverse impact on our cash flows, financial condition or results of operations in the future.

The potential impacts of climate change may negatively impact our business and results of operations.

Climate change has 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 (GHGs) may pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain GHGs, 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.

We depend on one purchaser for a substantial portion of our revenue in the United States. The inability of the purchaser to meet their payment obligations to us may adversely affect our financial results.

Currently, Nautilus relies on its contract with Plains Marketing, LP. as the sole customer for its oil produced in Montana. If Nautilus' sole customer reduces or discontinues its business with us, or if we are not able to successfully negotiate a replacement contract with our sole customer after the expiration of such contract, or if the replacement contract is on less favorable terms, the effect on us could be adverse if we were not able to locate new customers to purchase the oil produced at the Poplar Field. In addition, if Nautilus' sole customer was to experience financial difficulties or any deterioration in its ability to satisfy its obligations to us, our cash flow from the Poplar Field could be adversely affected.

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 annual report and the documents incorporated by reference in this annual report contain estimates of our proved 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.

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.

Reserves as of June 30, 2011 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, 2011 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, 2011 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 new 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 MPAL's 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 the Company's 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 proved 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.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may 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. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;

- adverse weather conditions;
- compliance with environmental and other governmental requirements including the Bureau of Indian Affairs and the Bureau of Land Management; and
- costs of, or shortages or delays in the availability of, drilling rigs, pressure pumping equipment and supplies, tubular materials, water resources, disposal facilities, other necessary equipment, supplies and services.

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

The Company follows 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. The Company records its 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 affected, the proved developed reserves will be increased to the lesser of the current risk adjusted probable and possible reserves or the newly contracted quantities. At June 30, 2011, Mereenie had no gas contracts, thus no gas reserves. The Mereenie discounted future net cash flows were negative due to the loss of the gas contract. According to the SEC definition of proved reserves, this results in zero proved oil reserves. 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;
- 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 and results of operation.

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 generated in the U.S. dollar in the future. However, at June 30, 2011, the U.S. dollar has weakened against the Australian dollar which has had, and may continue to have, a positive 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, 2011 was $9.2 million and is included in accumulated other comprehensive income on the balance sheet. Any continued 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.

Item 1B. ***Unresolved Staff Comments.***

None

Item 3. ***Legal Proceedings***

None

Item 4. ***Removed and Reserved.***

PART II

Item 5. ***Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Securities***

(a) *Principal Market*

The principal market for MPC's common stock is the NASDAQ Capital Market under the symbol **MPET**. The stock is also traded on the Australian Stock Exchange in the form of CHESS depository interests under the symbol **MGN**. The quarterly high and low prices on the most active market, NASDAQ, during the quarterly periods indicated were as follows:

2011	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
High	1.97	3.03	3.45	2.58
Low	1.49	1.78	2.27	1.38

2010	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
High	1.59	1.76	2.42	2.26
Low	0.91	1.30	1.53	1.54

(b) *Approximate Number of Holders of Common Stock at September 1, 2011*

Title of Class	Number of Record Holders
Common stock, par value $.01 per share	5,454

(c) *Frequency and Amount of Dividends*

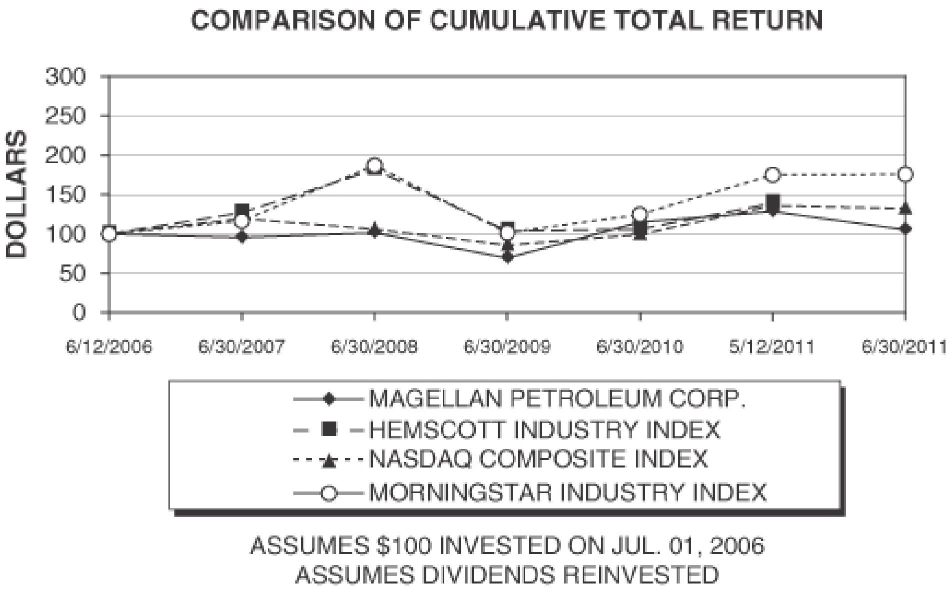
MPC has never paid a cash dividend on its common stock. The Company does not intend to pay cash dividends in the foreseeable future.

Table of Contents

(e) *Performance Graph*

The graph below compares the cumulative total returns, including reinvestment of dividends, if applicable, on the Company's common stock with the returns on companies in the NASDAQ Composite Index, a broad equity market index, and Morningstar Oil and Gas E&P Industry Index Morningstar Industry Index ("Morningstar Industry Index"), an industry group index.

The chart displayed below is presented in accordance with SEC requirements. The graph assumes a $100 investment made on July 1, 2006 and the reinvestment of all dividends. Stockholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future performance.



The Hemscott Oil & Gas Index, the industry group index formally used in the MPET graph is no longer available due to Morningstar's acquisition of Hemscott, and it has been replaced in the performance graph with Morningstar's Oil and Gas E&P Industry index, an index deemed to be the closest fit by composition and construction.

Company/Market/Peer Group	6/30/2006	6/30/2007	6/30/2008	6/30/2009	6/30/2010	5/12/2011	6/30/2011
Magellan Petroleum Corporation	$100.00	$ 95.60	$101.89	$ 69.81	$115.09	$128.93	$105.66
NASDAQ Composite Index	$100.00	$119.88	$106.36	$ 85.99	$ 99.73	$136.44	$132.36
Morningstar Industry Index	$100.00	$116.77	$187.29	$101.82	$124.81	$175.35	$175.99
Hemscott Industry Index	$100.00	$126.95	$181.93	$104.27	$106.55	$139.05	n/a

Recent Sales of Unregistered Securities

As previously disclosed in the Company's reports filed on May 14, 2010, February 10, 2009, April 8, 2009, June 2, 2009 and July 14, 2009, the Company entered into a Securities Purchase Agreement (the "Purchase Agreement"), dated February 9, 2009, with Young Energy Prize S.A. ("YEP") under which the Company agreed to sell, and YEP agreed to purchase, 8,695,652 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 $10,000,000. The 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. The Company received gross proceeds of $10 million, which was used for acquisitions as well as, 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 private placement and the Warrant Shares are not registered under the Securities Act of 1933, as amended ("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 SEC or an available exemption from the applicable federal and state registration requirements. In the Purchase Agreement, YEP represents to the Company that: (a) it is an accredited investor, as such term is defined in Rule 501 of Regulation D promulgated under the Securities Act; (b) it will acquire the Shares and the Warrant as principal for its own account for investment purposes only and not with a view to or for distributing or reselling the shares and the Warrant or any part thereof, and (c) it is knowledgeable, sophisticated, and experienced in making, and qualified to make, decisions with respect to investments in securities representing an investment decision similar to that involved in the purchase of the shares and the Warrant. The Company has relied on the exemption from the registration requirements of the Securities Act set forth in Regulation S promulgated thereunder for purposes of the YEP transaction.

On October 14, 2009, the Company entered into a Purchase and Sale Agreement (the "Nautilus Purchase Agreement"), dated October 15, 2009, with White Bear LLC, a Montana limited liability company ("White Bear") and YEP I, SICAV-FIS, a Luxembourg entity ("the YEP I Fund", and collectively with White Bear, the "Sellers") and simultaneously closed the transactions described therein. Under the Nautilus Purchase Agreement, the Company acquired from the Sellers an 83.5% controlling ownership interest in Nautilus, a Montana limited liability company. The Company paid gross $10.9 million for the controlling interest in Nautilus, comprised of a cash payment totaling approximately $7.3 million and the issuance of 1.7 million new shares of Common Stock, valued by the parties at $2,380,000 (or $1.40 per share), with an adjustment for $1.2 million of net debt. All shares of Common Stock sold pursuant to the Nautilus Purchase Agreement were registered in the name of the YEP I Fund. The shares sold to YEP I Fund in the private placement 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 SEC or an available exemption from the applicable federal and state registration requirements. In the Nautilus Purchase Agreement, YEP I Fund represents to the Company that: (a) it is an accredited investor, as such term is defined in Rule 501 of Regulation D promulgated under the Securities Act; (b) it will acquire the shares for its own account for investment purposes only and not with a view to or for distributing or reselling the shares or any part thereof, and (c) it is knowledgeable, sophisticated, and experienced in making, and qualified to make, decisions with respect to investments in securities representing an investment decision similar to that involved in the purchase of the shares. The Company relied upon the exemption from the registration requirements of the Securities Act provided by Regulation S promulgated under the Securities Act.

On August 5, 2010, the Company entered into another Securities Purchase Agreement (the "Second Purchase Agreement") with YEP, under which the Company agrees to sell, and YEP agrees that YEP and/or one or more of its affiliates (collectively, the "Investor") will purchase 5,200,000 shares of Common Stock at a purchase price of $3.00 per share, for an aggregate purchase price of $15.6 million (such transaction referred to below as the "Investment Transaction"). Pursuant to the terms of the Second Purchase Agreement, the Company shall use the proceeds from the Investment Transactions to facilitate the closing of the Evans Shoal Transaction. The shares to be issued to the Investor in connection with the Investment Transaction have not been registered under the Securities Act, and may not be offered or sold in the United States in the absence of an effective registration statement or exemption from the registration requirements of the Securities Act. In the Second

Purchase Agreement, the Investor represented to the Company that: (a) it is an accredited investor, as such term is defined in Rule 501 of Regulation D promulgated under the Securities Act; (b) it will acquire the shares for its own account for investment purposes only and not with a view to or for distributing or reselling the shares or any part thereof, and (c) it is knowledgeable, sophisticated, and experienced in making, and qualified to make, decisions with respect to investments in securities representing an investment decision similar to that involved in the purchase of the shares.

On February 11, 2011, the Company and YEP executed a First Amendment to Securities Purchase Agreement (“First Amendment”). The First Amendment provides for a final closing of the Investment Transaction on or before June 15, 2011 to the extent that: (i) the Evans Shoal Transaction does not close as contemplated by the Asset Sales Deed; and (ii) the failure to close the Evans Shoal Transaction results in the failure of the Company to recover an additional $10 million deposit made towards the purchase price set forth of the Asset Sales Deed (the “Deposit Back Stop”). On February 17, 2011, the Company and YEP executed a Second Amendment to Securities Purchase Agreement (“Second Amendment”) to clarify that the Deposit Back Stop set forth in the First Amendment and states that the funding contemplated by the First Amendment would not be withheld to the extent that the Company fails to satisfy any condition precedent set forth in the Second Purchase Agreement if such non-satisfaction is reasonably attributable to the failure to close the Evans Shoal Transaction. Since the Asset Sales Agreement has been terminated and MPAL did receive the $10 million deposit back in July 2011, the Investment Transaction has not closed. The Company and YEP are in the process of terminating the Securities Purchase Agreement as amended by the First and Second Amendments.

Please refer to Note 20 for details of all subsequent events.

Issuer Purchases of Equity Securities

The following table sets forth the number of shares that the Company has repurchased under any of its repurchase plans for the stated periods, the cost per share of such repurchases and the number of shares that may yet be repurchased under the plans:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan (1)	Maximum Number of Shares that May Yet Be Purchased Under Plan
July 1, 2010 – June 30, 2011	—	—	—	319,150

(1) The Company through its stock repurchase plan may purchase up to one million shares of its common stock in the open market. Through June 30, 2011, the Company had purchased 680,850 of its shares at an average price of $1.01 per share, or a total cost of approximately $686,000, all of which shares have been cancelled. No shares were purchased during 2011, 2010, or 2009.

Item 6. *Selected Financial Data.*

The following table sets forth selected data (in thousands except for exchange rates and per share data) and other operating information of the Company. The selected consolidated financial data in the table, except for the exchange rate, are derived from the consolidated financial statements of the Company. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

	Years Ended June 30,				
	2011	2010	2009	2008	2007
Financial Data					
Total revenues	$ 18,177	$28,525	$28,191	$40,895	$30,675
Net (loss) income attributable to MPC	(32,433)	(1,447)	665	(8,892)	447
Net (loss) income per share (basic and diluted) attributable to MPC	(0.62)	(0.03)	0.02	(0.21)	0.01
Total assets	71,575	90,706	71,704	85,295	85,616
Long-term liabilities	12,578	10,775	11,809	14,153	13,076
Non-controlling interests	1,989	1,914	—	—	—
Exchange rate A.$ = U.S. at September 1	1.07	0.89	0.84	0.86	0.82

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

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 filing, 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 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 the following: the ability of Magellan and Santos to complete and implement the terms of the Santos asset swap/sales agreement and gas sales contract, including securing the customary approvals necessary to complete the asset swap, the future outcome of the negotiations by Santos with its customers for gas sales contracts for the remaining uncontracted reserves in the Amadeus Basin, the production volume at Mereenie and whether it will be sufficient to trigger the bonus amounts provided for in the Santos asset swap/sales agreement, the ability of the Company to successfully develop its existing assets, the ability of the Company to secure gas sales contracts for the uncontracted reserves at Dingo, the ability of the Company to implement a successful exploration program, pricing and production levels from the properties in which Magellan and MPAL have interests, the extent of the recoverable reserves at those properties, the profitable integration of acquired businesses, including Nautilus Poplar LLC, the likelihood of success of the drilling program at the Poplar Fields by the Company's new farm-in partner, VAALCO Energy, and the results of the ongoing production well tests in the U.K. In addition, MPAL has a large number of exploration permits and faces the risk that any wells drilled may fail to encounter hydrocarbons in commercially recoverable quantities. Any forward-looking information provided in this report should be considered with these factors in mind. Magellan assumes no obligation to update any forward-looking statements contained in this report, whether as a result of new information, future events or otherwise.

Executive Summary

Overview

Magellan is an oil and gas investment company, whose strategy is to create long-term value through the acquisition and redevelopment of "under-exploited" natural gas and oil reserves.

Although Magellan has been in existence for decades, particularly in Australia, the Company began the transformation to an active international E&P development platform only in the past two years. During this time, the Company has assembled a new management team with experience in oil and gas operations, project development, finance, and management. This team has worked to rationalize Magellan's legacy assets, contracts, and holding structures, while positioning the Company to unlock the value of the most promising of these assets and expanding its scope to gain access to new growth opportunities.

In the past year, the Company dedicated significant time and resources to pursuing the acquisition of Santos' 40% interest in a contingent 6.6 Tcf gas field in the Northern Territory, Australia, the Evans Shoal field. This transaction would likely have been transformational for Magellan. The development of the field using Methanol technology represented a creative solution to an otherwise long-term, stranded natural gas field. Despite spirited effort, due to factors outside of the Company's control, Magellan and Santos agreed that the transaction would not be completed. The Company had committed A$25 million towards the acquisition of the Evans Shoal field through two deposits and was returned A$10 million on July 22, 2011.

As a result, the Company continued with a review of its assets and developed a rationalization plan. On September 14, 2011, Magellan entered into an agreement with Santos to swap its interest in the Mereenie field for the purchase of the remaining interest in the producing Palm Valley gas field and exploration Dingo field, all three fields located in the Amadeus basin, onshore Australia. Upon completion of this transaction, which is subject to customary approvals and expected to close in the very near future, the Company will receive the new asset interests described above, a cash contribution of A$25 million, and further subsequent bonus payments contingent upon future production, with a cumulative possible value of A$17.5 million. In addition, the Company also entered into a long term gas supply agreement with Santos for its Palm Valley gas field, which will provide incremental revenue and cash flows to support the Company's ongoing operations in Australia.

In parallel, the Company focused on its under-developed, multiple formation, producing oil field in Montana, the Poplar Field. Building from the acquisition of 3D seismic in 2010, and the acquisition of a set of cores and further data from a new well spud in 2010, the Company entered into a farm out agreement with VAALCO Energy for the Bakken and deep formations of the Poplar Field. VAALCO Energy committed to drill three new wells in the Poplar Field by December 2012 and paid $5 million on September 6, 2011 in consideration for a 65% working interest in these Deep Intervals. The Company will retain a 35% working interest in the Deep Intervals and will continue to hold its current interest in all formations above the Bakken formation, including the currently producing Charles and Tyler formations where all Poplar proved and probable reserves are located. This transaction will enable the Company to continue to focus on the development of the Charles formation while also testing the Bakken, Red River and other potential deep formations in the Poplar Field.

In the U.K., Magellan participated in the Markwells Wood-1 oil discovery. The well was spud, by Northern Petroleum in November 2010. A completion rig moved on site in September, 2011 to begin a series of incremental reservoir tests designed to measure oil flow response to several production strategies.

The financial results for fiscal year ending June 30, 2011 resulted in a consolidated loss of $32.4 million, or $0.62 per share. The net loss was largely the result of non-recurring charges of approximately $23.3 million, including $15.9 million relating to the Evans Shoal deposit and $7.0 million relating to the valuation allowance for deferred tax assets. In addition, the Company incurred materially higher consulting costs and expenses related to the transactions pursued during the fiscal year ending June 30, 2011. The financial results of the Company were particularly negatively impacted by the $10.3 million reduction in consolidated revenues from FY 2010 to FY 2011, which primarily resulted from the end of the gas sales contract at Mereenie and the reduction in gas sales volume from Palm Valley. The reduction in revenues from the Company's Australian operations underpinned the completion of the rationalization plan described above.

The Company has now completed a series of key transactions that will enable (a) increased control over its asset portfolio, (b) several new, concurrent development programs for the Poplar Field, and (c) provide incremental resources to fund existing development plans and new opportunities.

Overview of our FY 2011 Financial Results

Magellan realized a 87% decrease in gas sales this fiscal year due to the term end of the Mereenie Sales Agreement and the volume decrease at Palm Valley which is according to the Palm Valley Contract, resulting in years ended June 30, 2011 gas sales of $1.8 million (net of royalties) or 10% of total revenues for the years ended June 30, 2011 and was offset by a 12.1% increase in the average exchange rate and a 1% increase in the average price per MCF received under the Palm Valley contract.

Oil sales increased by 20% this fiscal year due to oil sales related to the Poplar Field assets acquired in October 2009 and March 2010 and a 15% increase in the price per barrel in the United States resulting in years ended June 30, 2011 oil sales of $11.8 million (net of royalties) or 65% of total revenues for the years ended June 30, 2011.

For the year ended June 30, 2011, Magellan recorded a consolidated net loss of $32.4 million, or $0.62 per share, on gross revenues of $18.2 million, as compared to a net loss of $1.5 million, or $0.03 per share, on gross revenues of $28.5 million in 2010. The following items impacted our 2011 earnings and cash flow as compared to 2010:

- Gas sales decreased from $13.6 million in 2010 to $1.8 million in 2011 due to the term end of the Mereenie Sales Agreement (MSA4)
- $15.9 million relates to a write off of the initial "deposit" contributed by Magellan Petroleum Australia Limited ("MPAL"), the Company's wholly owned subsidiary, in connection with the March 25, 2010 Asset Sales Deed, as amended by the Deed of Variation, between MPAL and Santos Offshore Pty Ltd. ("Asset Sales Deed") which outlined the terms of MPAL's contemplated purchase of Santos' 40% interest in the Evans Shoal natural gas field (NT/P48) ("Evans Shoal Transaction")
- $7.0 million is attributable to a non-cash charge related to a valuation allowance recognized as a reserve against MPAL's deferred tax balances

On August 30, 2011, the Company reported a preliminary unaudited consolidated net loss of $36.1 million, or $0.69 per share for the year ended June 30, 2011. The audited financial statements for the same period report a consolidated net loss of $32.4 million or $0.62 per share. The difference in the preliminary and audited consolidated net loss numbers results from the reversal of a $4 million impairment to MPAL's Goodwill included in the unaudited results. At the time of the release of the Company's preliminary unaudited financial statements, the Company had yet to complete its annual Goodwill impairment analysis, which upon finalization resulted in no impairment to MPAL's Goodwill.

The net loss in the fiscal year ended June 30, 2011 income was largely the result of non-recurring charges.

The new commercial arrangements recently concluded are as follows:

On September 14, 2011, Magellan Petroleum (N.T.) Pty Ltd ("Magellan NT"), a wholly owned subsidiary of MPAL, entered into a Sale Agreement ("Santos SA") with Santos QNT Pty Ltd ("Santos QNT") and Santos Limited ("Santos Entities"). The Santos SA provides for the transfer of Magellan NT's 35% interest in the Mereenie oil and gas field to the Santos Entities and the transfer of the Santos entities 47.977% interest in the Palm Valley gas field and the 65.6635% interest in the Dingo gas field to Magellan NT subject to the satisfaction of certain conditions.

The cash consideration payable to Magellan NT is A$25 million plus a bonus amount based on Mereenie future production levels.

Upon completion of the Santos SA, Magellan NT entered into a Gas Supply and Purchase Agreement (the "GSPA") with the Santos Entities on September 14, 2011, and provides for the sale by Magellan NT to the Santos Entities of a total contract gas quantity of 25.65PJ over the anticipated 17 year term of the GSPA.

On September 2, 2011, the Company signed and closed a Purchase and Sale Agreement with the owners of Nautilus Technical Group LLC, ("Nautilus Technical"), and Eastern Rider LLC, ("Eastern Rider"), (collectively the "Sellers"), resulting in the Company owning 100% of Nautilus Poplar and, directly or indirectly through Nautilus, a 100% working interest in the Poplar Field, aside from certain working interest owners in the Northwest Poplar fields. The Company paid the Sellers total cash consideration of $4.0 million dollars.

On September 7, 2011, the Company and VAALCO Energy (USA) Inc. ("VAALCO") signed a definitive Lease Purchase and Sale Agreement (the "VAALCO LPSA"). VAALCO also agreed to drill three wells, at its sole expense as operator, to the Bakken formation and to formations below the Bakken (the "Deep Intervals") in Poplar Field. Upon completion of three (3) new wells in the Deep Intervals of the Poplar Field, VAALCO will earn a 65% working interest in the Deep Intervals within the Poplar Field. One well will be spud on or before June 1, 2012 and the second and third will be spud on or before December 31, 2012. One well will be drilled horizontally to test the Bakken Formation, one well will be drilled vertically to test the Red River Formation, and a third will be targeted at VAALCO's discretion.

The Company will retain a 35% working interest in the Deep Intervals and will continue to hold its current interest in all formations above the Bakken formation, including the currently producing Charles and Tyler formations where all Poplar proved and probable reserves are located.

Operational Results

Australia

MPC's Australia sale volumes, net of royalties, were .71 BCF of gas and 55 MBbls of oil for the years ended June 30, 2011 or a 79% decrease in gas sales and 57% decrease in oil sales for the years ended June 30, 2010. The decrease in gas sales is due primarily to the term end of the MSA4 agreement and the decrease in oil sales is due primarily to the sale of the Cooper Basing and Nockatunga assets

Mereenie: There were no gas sales from Mereenie for the years ended June 30, 2011. The Mereenie Producers continued to supply PWC's gas requirements on a reasonable endeavors basis to supplement Blacktip gas sales until early February 2010. The principal Mereenie contracts and supply obligations under the various agreements expired in January and June 2009, and September 2010.

Magellan NT has entered into the Santos SA to transfer all of the Company's interest in the Mereenie field to the Santos Entities with effect July 1, 2011, as described above.

Palm Valley: The Palm Valley gas contract expires in January 2012.

Magellan NT has entered into the Santos SA to receive all of the Santos Entities' interest in the Palm Valley and Dingo fields with effect July 1, 2011, as described above. Upon completion of the agreements, The Company will own 100% of the Palm Valley and Dingo gas fields and will have 25.65PJ of gas contracted under the GSPA with the Santos Entities.

Dingo: MPAL has a 34.34% interest in the Dingo gas field which is held under Retention License No. 2 in the Amadeus Basin in the Northern Territory. No market has emerged for gas volumes that have been discovered in the Dingo gas field. MPAL's share of potential production from this permit area is subject to a 10% statutory government royalty and overriding royalties aggregating 4.81%. The license was renewed for a further five year term and expires in February 2014

Evans Shoal (NT/P48): MPAL entered into an agreement with Santos Offshore Pty Ltd ("Santos") on March 25, 2010 ("Asset Sales Deed"), to purchase Santos' 40% interest in the Evans Shoal natural gas field (NT/P48) ("Evans Shoal Transaction").

On July 21, 2011, Santos and MPAL executed a Release Agreement to (1) terminate the Amended Asset Sales Deed and (2) resolve all outstanding issues relating to the Amended Asset Sales Deed. Under the Release Agreement, MPAL received back the Second Escrow Deposit, plus all interest accrued on that deposit from the date of deposit to the date of release and the parties agreed to mutually release each other from all claims arising out of the Asset Sales Deed and the Evans Shoal Transaction.

In connection with the unwinding of the Evans Shoal Transaction, the Company and Santos on September 14, 2011 executed agreements to transfer their interests in the Amadeus licenses with a resulting ownership interest by the Company of 100% of the Palm Valley and Dingo gas fields.

NT/P82: The Commonwealth — Northern Territory Offshore Petroleum Joint Authority granted Exploration Permit for Petroleum NT/P82 to the Company (100% interest) over Area NT09-1. Area NT09-1 was offered for competitive bid under the Australian Government 2009 Release of Offshore Petroleum Exploration Areas. The exploration permit was granted on May 13, 2010 for a six year term. The committed work program under the permit during the first three years of the term involves the reprocessing of existing seismic data, the acquisition of additional 2D and 3D seismic data and the interpretation of the combined seismic database. NT/P82 lies to the south and southeast of the Evans Shoal gas field within the Bonaparte Basin.

Table of Contents

Magellan undertook the reprocessing of 2,061 miles of existing 2D seismic data during the first year of the permit and planning has commenced to undertake the acquisition of 62 miles of 2D and 46 square miles of 3D seismic data during the second permit year. Acquisition of the seismic surveys is planned for the first quarter of 2012. At years ended June 30, 2011, MPAL's share of the work obligations committed for the NT/P82 permit was $1,798,000.

Montana

MPC's Poplar Field's sale volumes, net of royalties, were 68 MBbls of oil for the years ended June 30, 2011 or 62% increase in oil sales for the years ended June 30, 2010. The increase is due primarily to the year over year effect of the oil sales related to the Poplar Field assets acquired in October 2009 and March 2010 and a 15% increase in the price per barrel in the United States.

Poplar Fields: On a consolidated basis, MPC, through Nautilus and directly, owned an average 85.7% working interest in the Poplar Fields in Montana as of June 30, 2011.

On September 2 and September 6, 2011, the Company completed transactions to consolidate its working interest in the Poplar Fields and sell 65% of its working interest in the Deep Intervals to VAALCO, respectively, as described above.

The Company has initiated a program in late summer 2011 to undertake seven recompletions along with the completion of the EPU119 drilled last fall into the Charles Formation. Magellan also plans to drill one shallow natural gas well in fall of 2011 to evaluate significant reservoir pressure differentials seen in the shallow gas horizon during the drilling of the EPU119 well.

A second drilling program, including up to three new infill wells in the Charles Formation, is planned for the fall of 2011. Drilling will be based upon the results from the recompletion program with the objective of increased production resulting in increased cash generation amid high oil price netbacks.

Given the complexity of the Poplar reservoir, the Company has completed the first steps of a reservoir engineering study for the Charles Formation. Further work is being conducted to manage and monitor water influx, determine new high potential drilling sites, and to determine the merit of an infill program.

United Kingdom

The Company participated in the Markwells Wood-1 exploration well in PEDL 126, which spud in November 2010. Northern Petroleum is operator of the PEDL 126 joint venture. Markwells Wood-1 well targeted the eastward extension of the Horndean oil field which is currently producing from the Great Oolite Formation. Assessment of the well logs confirmed that the entire Great Oolite reservoir sequence in Markwells Wood-1 is oil-bearing above the Horndean field oil-water contact of 4,446 ft sub-sea level. Northern Petroleum started operations for an extended well test of the Markwells Wood oil discovery in West Sussex, with the arrival of a workover rig on September 6, 2011. The test will enable the joint venture partners to evaluate the potential and scheme for future development of the Markwells Wood oil accumulation.

Magellan has a gross 240,000 acre Weald Basin position in Southern England, U.K., which is a newer, less mature shale play, where Magellan is a 50% partner with Celtique Energie. The Weald Basin shale play is unexplored and is based on the Lower Jurassic (Liassic) shale which lies in both the oil and gas window. There are currently no producing wells in the license area; however, with the recent developments in shale development technology, coupled with the Basin's proximity to U.K. and NW European oil and gas markets and infrastructure, these licenses are an attractive opportunity for near term development. The Company's goal is to establish near-term monetization and strategic drilling programs for U.K. shale acreage.

Critical Accounting Estimates

Oil and Gas Properties

The Company follows the successful efforts method of accounting for its oil and gas operations. Under this method, the costs of successful wells, development dry holes, productive leases, and permit and concession costs 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. The Company records its proportionate share in joint venture operations in the respective classifications of assets, liabilities and expenses. Unproved properties with significant acquisition costs are periodically assessed for impairment in value, with any 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 are reviewed for impairment whenever events or changes in 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 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 risk adjusted probable and possible reserves or the newly contracted quantities.

Exploratory drilling costs are initially capitalized pending determination of proved reserves but are charged to expense if no proved reserves are found. Other exploration costs, including geological and geophysical expenses, leasehold expiration costs and delay rentals, are expensed as incurred. Because the Company follows the successful efforts method of accounting, the results of operations may vary materially from quarter to quarter. An active exploration program may result in greater exploration and dry hole costs.

Historically, we have adjusted our depletion rates during the year when new reserve information is available. For the year ended June 30, 2010, we adopted the current SEC accounting and disclosure regulations for oil and gas companies effective June 30, 2010. The change in price encompassed in the new SEC rules was a change in accounting principle inseparable from a change in estimate for 2009 and was accounted for prospectively. The price used under the current rules is a 12 month average price on the first day of the month for the 12 month reporting period. The price used in periods prior to fiscal year 2010 was the price on the last day of the reporting period. There was no measurable difference in the two prices and as such there was no material dollar impact caused by the change, for fiscal year 2010.

Table of Contents

Nondepletable assets

At June 30, 2011, 2010 and 2009 oil and gas properties include $8.1 million, $4.3 million and $6.6 million, respectively, of capitalized costs that are currently not being depleted pending the determination of proved reserves. Components of these costs are as follows:

Nondepletable capitalized costs	2011	2010	2009
United Kingdom (1)			
Balance beginning of year	$3,576,518	$ 3,154,266	$2,978,172
Additions to capitalized costs	1,703,285	608,479	485,725
Charged to expense	35,814	(231,798)	(257,519)
Exchange adjustment	(55,892)	45,571	(52,112)
Balance end of year	$5,259,725	$ 3,576,518	$3,154,266
United States (2)			
Balance beginning of year	$ 313,710	$ —	$ —
Additions to capitalized costs	2,406,210	313,710	—
Reclassified to producing properties	(277,417)	—	—
Charged to expense	(31,934)	—	—
Balance end of year	$2,410,569	$ 313,710	$ —
Australia (3)			
Balance beginning of year	$ 415,108	$ 3,486,611	$3,852,698
Assets sold or held for sale	—	(3,071,503)	—
Charged to expense	—	—	(63,739)
Exchange adjustment	—	—	(302,348)
Balance end of year	$ 415,108	$ 415,108	$3,486,611
Total			
Balance beginning of year	$4,305,336	$ 6,640,877	$6,830,870
Additions to capitalized costs	4,109,495	922,189	485,725
Assets sold or held for sale	—	(3,071,503)	—
Reclassified to producing properties	(277,417)	—	—
Charged to expense	3,880	(231,798)	(321,258)
Exchange adjustment	(55,892)	45,571	(354,460)
Balance end of year	$8,085,402	$ 4,305,336	$6,640,877

(1) Of this amount, $1.9 million relates to the stepped up value of the U.K. exploration permits and licenses, which was recorded in the 2006 acquisition of the 44.87% remaining interest of MPAL. The step up value of these licenses and permits are evaluated for impairment annually. The balance represents capitalized exploratory well costs, initiated in 2007, pending discovery and production of reserves.

(2) U.S. capitalized exploratory well costs initiated in 2010, pending discovery and production of reserves.

(3) Australia exploration permits and licenses are evaluated annually or when events or changes in circumstances indicate that the carrying value, related to the step up to fair value for the 44.87% remaining interest of MPAL acquired in 2006, may be impaired. During the fiscal year ended June 30, 2010, Cooper Basin assets were sold. Prior costs were capitalized during the fiscal year ended June 30, 2006 and remained capitalized through the date of the sale as the related well had a sufficient quantity of reserves to justify its completion as a producing well.

Goodwill

The aggregate amount of goodwill is $4,695,204 at June 30, 2011 and 2010, of which $4,020,706 is related to the fiscal 2006 acquisition of the 44.87% of MPAL that we did not own at the time and $674,500 is attributable to the October 15, 2009 acquisition of Nautilus.

Goodwill is not amortized but is tested for impairment annually or whenever events or changes in circumstances indicate that the carrying value may be impaired. Our annual impairment testing date for MPAL related goodwill is June 30 and is October 1 for Nautilus.

Goodwill is tested for impairment using a two-step process.

- Step one — the fair value of each reporting unit is compared to its carrying value in order to identify potential impairment. If the fair value of a reporting unit exceeds the carrying value of its net assets, goodwill is not considered impaired and no further testing is required. If the carrying value of the net assets exceeds the fair value of a reporting unit, potential impairment is indicated and step two of the impairment test is performed in order to determine the implied fair value of the reporting unit's goodwill and measure the potential impairment loss.
- Step two — when potential impairment is indicated in step one, we compare the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. Determining the implied fair value of goodwill requires a valuation of the reporting unit's tangible and intangible assets and liabilities in a manner similar to the allocation of the purchase price in a business combination. Any excess of the value of a reporting unit over the amounts assigned to its assets and liabilities is referred to as the implied fair value of goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. At June 30, 2011, Magellan passed step one and therefore the Company concluded step two was not necessary, as no impairment existed.

Determining the fair value of a reporting unit involves the use of significant estimates and assumptions.

We employed the adjusted net assets method to estimate the fair value of MPAL at June 30, 2011. This method entails estimating the fair value of all of MPAL's balance sheet items as of the valuation date. The Company has utilized the Market Approach, specifically the Similar Transaction Method ("STM") in order to estimate the fair value of MPAL's acreage and oil and natural gas reserves (collectively, the "MPAL Reserves") on the balance sheet. The MPAL Reserves are reflected on the balance sheet as Oil and Gas Properties. This line includes Exploration Phase petroleum properties (i.e. exploratory acreage) and Production Phase petroleum properties (i.e. proved and probable oil and natural gas reserves). In its application of the STM, the Company reviewed publicly available transaction data for the sale of comparable resources in the U.K. and Australia in order to estimate the fair value of MPAL Reserves. If the adjusted equity value, after considering the fair values of the assets and liabilities, is greater than the carrying value of MPAL, then no impairment is indicated. Management believes that this methodology is most meaningful since the highest and best use of these assets would be to continue to hold and exploit the assets over time. No impairment existed as the adjusted fair value exceeded the carrying value by 25%, as of June 30, 2011.

The fair value of our oil properties are estimated using a form of the market approach, which consists of a review of similar transactions that have occurred in the marketplace for proved and risk adjusted probable and possible reserves. Accordingly, we have reviewed implied prices per thousand cubic feet equivalent associated with market-based transactions in similar geographic locations for each of our oil properties, and selected appropriate metrics based on a qualitative comparison between our oil properties and the relevant transactions.

The fair value of our non-depletable exploration permits and licenses is estimated based on a review of similar transactions that have occurred in the marketplace. Accordingly, we have reviewed implied prices per acre associated with market-based transactions in similar geographic locations for our non-depletable exploration permits and licenses, and selected appropriate metrics based on a qualitative comparison between our non-depletable exploration permits and the relevant transactions.

At October 1, 2010, we performed our annual impairment test of the Nautilus goodwill. We employed both the income approach (discounted cash flow method) and the market value approach in estimating the fair value of Nautilus. As of October 1, 2010, no impairment existed as the indicated fair value of Nautilus, based upon our estimate, exceeded its carrying value by 48% as of October 1, 2010.

Asset Retirement Obligations

Legal obligations associated with the retirement of long-lived assets are recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, the cost is capitalized as part of the related long-lived asset (oil & gas properties) and amortized on a units-of-production basis over the life of the related reserves. Accretion expense in connection with the discounted liability is recognized over the remaining life of the related reserves.

The estimated liability is based on the future estimated cost of land reclamation, plugging the existing oil and gas wells and removing the surface facilities equipment in our operating fields. The liability is a discounted liability using a credit-adjusted risk-free rate on the date such liabilities are determined. Revisions to the liability could occur due to changes in the estimates or timing of these costs, acquisition of additional properties and as new wells being drilled.

Estimates of future asset retirement obligations include significant management judgment and are based on projected future retirement costs and timing. Judgments are based upon such things as field life and estimated costs. Such costs could differ significantly when they are incurred.

Income Taxes

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 management believes it is more likely than not that such assets will not be recovered. The current year increase in the valuation allowance is primarily due to a valuation allowance recorded against the Company’s Australian deferred tax assets. In evaluating the ability to recover these deferred tax assets, we considered all available positive and negative evidence, giving greater weight to the recent current loss, the absence of taxable income in the carryback period and the uncertainty regarding our ability to project financial results in future periods. Additionally, consistent with prior periods, the valuation allowance related to the Company’s U.S. and U.K. deferred tax assets increased due to the generation of U.S. net operating losses, U.S. foreign tax credits, tax benefits from U.K. exploration costs and U.K. net operating losses.

The Company evaluates uncertain tax positions, which requires 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 fiscal 2011 and 2010.

Business combinations

The Company applies the acquisition method of recording business combinations. Under this method, the Company recognizes and measures the fair value of identifiable assets acquired, the liabilities assumed 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 consultants as needed to assist us in assessing the fair value of other assets and liabilities assumed. Such valuations require management to make significant estimates and assumptions, especially with respect to the oil and gas properties.

Consolidated Liquidity and Capital Resources

Historically, we have funded our acquisition, exploration and development activities through cash from operations and debt facilities at Nautilus. Magellan’s corporate plan is to add long-term value and growth through the acquisition and redevelopment of "under-exploited" natural gas and oil reserves.

The Company estimates that its capital expenditures for the fiscal year ending June 30, 2012 to amount to approximately $33.6 million, arising from our operations in the U.S., Australia, and the U.K. of $29.4 million, $2.0 million and $2.2 million, respectively. The Company has complete discretion over the expenditures in the U.S. and will be able to adjust them in accordance with its funding priorities and strategy. The Company intends to fund these capital expenditures with cash on hand and cash flow from operations, including the proceeds received from transactions described in the subsequent events footnote (see Note 20).

Consolidated

The Company on a consolidated basis had approximately $20.4 million of cash and cash equivalents at June 30, 2011 and $33.6 million at June 30, 2010. 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. Cash balances were $14.0 million as of June 30, 2011 and the remaining $6.4 million was held in time deposit accounts in several Australian banks that have terms of 90 days or less.

When considering our liquidity and capital resources, we consider cash and cash equivalents since all of these amounts are available to fund operating, exploration and development activities.

The factors favorably impacting our liquidity and capital resources during the year ended June 30, 2011 included:

- effect of exchange rate changes on cash and cash equivalents of $4.2 million.

Factors contributing to a decrease in our liquidity and capital resources during the year ended June 30, 2011 included:

- $10.0 million escrow account deposit paid in February 2011, towards the Evans Shoal Purchase Price; which was refunded in full on July 22, 2011;
- $4.6 million expended for property & equipment and exploration activities; and
- $4.5 million expended for operating activities.

Cash provided by operating activities for the year ended June 30, 2011 decreased $8.4 million from the year ended June 30, 2010 as discussed below:

Cash from oil and gas revenues decreased approximately $12.5 million over the prior year due to the following:

Australian oil and gas sales volume decreased resulting from the sale of our Cooper Basin and Nockatunga assets, natural oil field declines of Mereenie and reduced sales due to the Blacktip Field coming online leading to the end of Mereenie MSA 4 contract in February 2010. This was offset by the receipts generated from MPAL's portion of the Power and Water Corporation ("PWC") contract settlement, increased U.S. oil sales and the 12.1% increase in the average foreign exchange rate, as well as a 15% oil price increase over the prior year at Poplar Field.

Operating cash outflows decreased approximately $5.2 million over the prior year due to the following:

- $2.3 million decrease in our accounts payable pay down; and
- $6.1 million decrease in taxes paid due to the expectation that MPAL would have a smaller tax liability.

Offset by,

- $0.9 million increase in salaries and benefits due to the severance payment made to a former officer and the year over year costs associated with the U.S. acquisition of Nautilus in October 2009;
- $0.6 million increase in accounting and legal expense due to the Evans Shoal Transaction;
- $1.6 million increase in exploration costs, primarily due to drilling in the United Kingdom.

The Company invested $4.6 million and $2.8 million in oil and gas exploration activities, which includes additions to property and equipment, during the fiscal years ended June 30, 2011 and 2010, respectively.

Effect of exchange rate changes

The value of the Australian dollar relative to the U.S. dollar increased 24% to $1.0591 at June 30, 2011 compared to a value of $0.8567 at June 30, 2010.

As to MPC

At June 30, 2011 MPC, on an unconsolidated basis, had working capital of $3.5 million. Working capital is comprised of current assets less current liabilities. On August 24, 2011, MPC borrowed $4.0 million from MPAL, this plus MPC's current cash position will be adequate to meet MPC's current obligations for the 2012 fiscal year.

As to MPAL

At June 30, 2011, MPAL had working capital of $27.0 million. Despite no SEC defined proved oil reserves, MPAL's future revenues in the long-term are expected to be derived from the sale of oil and gas in Australia. MPAL's current contract for the sale of Palm Valley gas will expire during fiscal year 2012 as does Amadeus Gas Trust revenues ($4.6 million), at June 30, 2011. Future oil revenues will be impacted by any volatility in the world price for crude oil. MPAL will strive to align operating expenses with any reductions in revenues.

On July 21, 2011, Santos and MPAL executed a Release Agreement to (1) terminate the Amended Assets Sale Deed and (2) resolve all outstanding issues relating to the Amended Asset Sales Deed. Under the Release Agreement, MPAL received back the additional A$10.0 million escrow deposit made towards the purchase price stipulated in the Amended Asset Sales Deed plus all interest accrued on that amount from the date of deposit to the date of release and the parties agreed to mutually release each other from all claims arising out of the Amended Asset Sales Deed and the Evans Shoal Transaction. Pursuant to the terms of the Amended Asset Sales Deed, the initial A$15.0 million deposit made towards the purchase price set forth in the Amended Asset Sales Deed was re-classified as non-refundable, and written off at June 30, 2011.

The process of unwinding the Evans Shoal Transaction has allowed the Company and Santos to look at their joint operations in the Northern Territory, Australia. This has lead to productive discussions towards rationalizing and more efficiently exploiting their respective interests in the Amadeus Basin, and creating new commercial opportunities. The Company has concluded their discussions with Santos at the time of this filing. Please refer to Note 20.

As to Nautilus

At June 30, 2011, Nautilus had working capital of $0.3 million. At June 30, 2011, Nautilus has debt comprising a note payable of $1.4 million issued by a bank. In January 2011, Nautilus amended its existing long term debt agreement with the bank to increase its principal amount of indebtedness to $1,710,438 from $441,220. The term of the amended long term debt agreement runs through 2014. Proceeds from the increased debt will be used to finance capital activities. The variable rate of the note is based upon the Wall Street Journal Prime Rate (the index). The index was 3.25% at June 30, 2011, resulting in an interest rate of 6.25% per annum as of June 30, 2011. Under the note payable, Nautilus is subject to both financial and non-financial covenants. The financial covenant requires that Nautilus maintain a debt service coverage ratio, as defined, of 1.2 to 1.0, which is calculated based on Nautilus' annual tax return. As of June 30, 2011, based upon its FY 2010 tax return, Nautilus was in compliance with the financial covenant.

The Nautilus' demand note payable with the same bank is classified as short term debt, which consists of advances under a $1,000,000 business capital line, used by Nautilus, of credit of which there was $500 due on the line at June 30, 2011. This revolving line of credit secures a $25,000 credit card and a $25,000 letter of credit that is in favor of the Bureau of Land Management.

The Company has initiated a program in late summer 2011 to undertake seven recompletions along with the completion of the EPU119 drilled last fall through the Charles Formation. Magellan also plans to drill one shallow natural gas well in fall of 2011 to evaluate significant reservoir pressure differentials seen in the shallow gas horizon during the drilling of the EPU119 well.

A second drilling program, including up to three new infill wells in the Charles Formation, is planned for the fall of 2011. Drilling will be based upon the results from the recompletion program with the objective of increased production resulting in increased cash generation amid high oil price netbacks.

Off Balance Sheet Arrangements

None

Contractual Obligations

The following is a summary of our consolidated contractual obligations at June 30, 2011, in thousands:

	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	3-5 YEARS	MORE THAN 5 YEARS
Operating lease obligations	$ 1,387	$ 514	$ 581	$ 193	$ 99
Purchase obligations (1)	4,516	3,056	1,460	—	—
Asset retirement obligations-undiscounted	31,934	—	288	—	31,646
Note payable including interest (2)	1,541	622	919	—	—
Total	$39,378	$ 4,192	$ 3,248	$ 193	$ 31,745

(1) Represents firm commitments for exploration and capital expenditures related to MPAL. Firm Commitments decreased $2.7 million offset by a $1.4 million increase caused by a 24% increase in exchange rates over June 30, 2010. The decrease was due to the delay of portions of the U.K. work program. Although the Company is committed to these expenditures, some may be farmed out to third parties. Additional contingent expenditures of $30,463,000 which are not legally binding have been excluded from the table above and based on exploration decisions would be due as follows: $0 (less than 1 year), $3,621,000 (1-3 years), $26,842,000 (3-5 years), and $0 (greater than 5 years). Contingent expenditures increased $2.7 million over prior years reporting excluding the exchange rate effect.

(2) Includes interest at a 6.25% rate based on the rate at June 30, 2011.

Table of Contents

Results of Operations

2011 vs. 2010

REVENUES AND INVESTMENT INCOME

Changes in revenues and investment income are as follows:

	TWELVE MONTHS ENDED June 30, 2011	2010	$ Variance	% Variance
Oil sales	$11,815,231	$ 9,886,592	$ 1,928,639	$ 20%
Gas sales	1,796,405	13,615,755	(11,819,350)	(87%)
Other production related revenues	4,565,241	5,022,210	(456,969)	(9%)
Investment and other income	922,774	3,012,831	(2,090,057)	(69%)

Significant changes are discussed below.

OIL SALES INCREASED — In the U.S., oil sales increased $2,789,000 due to the year over year effect of the sales related to the Poplar Field assets acquired in October 2009 and March 2010 and a 15% increase in the price per barrel in the United States. In Australia, sales decreased due to the sale of the Cooper Basin and Nockatunga Assets ($2,305,000) in fiscal 2010, increased sales in the prior year resulting from de-oiling the Mereenie pipeline, offset by the 12.1% increase in the average exchange rate discussed below and a 17% increase in the price per barrel at Mereenie.

Oil unit sales (after deducting royalties) in barrels (bbls) and the average price per barrel sold during the periods indicated were as follows:

	TWELVE MONTHS ENDED JUNE 30, 2011 SALES		2010 SALES			
	BBLS	AVERAGE PRICE A.$ PER BBL	BBLS	AVERAGE PRICE A.$ PER BBL	% Variance BBLS	% Variance A.$ PER BBL
Australia:						
Mereenie field	55,043	99.67	68,344	85.50	(19%)	17%
Cooper Basin	—	—	1,086	83.62	*	*
Nockatunga project (1)	—	—	27,962	73.92	*	*
Total	55,043		97,392		*	*

	BBLS	AVERAGE PRICE U.S.$ PER BBL	BBLS	AVERAGE PRICE U.S.$ PER BBL	% Variance BBLS	% Variance U.S.$ PER BBL
United States:						
Poplar Field	67,859	$ 77.96	42,017	$ 67.88	62%	15%

* Not meaningful

(1) Nockatunga average price per bbl is net of crude oil transportation costs which are deducted from the gross sales price.

Amounts presented above for oil prices and below for gas prices in Australia are in Australian dollars to show a more meaningful trend of underlying operations. For the fiscal years ended June 30, 2011 and 2010, the average foreign exchange rates ($AUD to $USD) were .9893 and .8826 respectively.

Table of Contents

GAS SALES DECREASED primarily due to the end of Mereenie MSA4 contract in February 2010 ($14,200,000) and the volume decrease at Palm Valley which is according to the Palm Valley Contract, offset by the 12.1% increase in the average exchange rate discussed below and the 1% increase in the average price per MCF received under the Palm Valley contract.

	TWELVE MONTHS ENDED June 30,					
	2011 SALES		2010 SALES			
	BCF	AVERAGE PRICE A.$ PER MCF	BCF	AVERAGE PRICE A.$ PER MCF	% Variance BCF	% Variance A.$ PER MCF
Australia: Palm Valley	0.712	2.28	1.166	2.25	(39%)	1%
Australia: Mereenie	—	—	2.264	6.53	*	*
Total	0.712	2.28	3.430	5.07	(79%)	(55%)

* Not meaningful

OTHER PRODUCTION RELATED REVENUES are primarily MPAL's share of gas pipeline tariff revenues which decreased as a result of an increase in Amadeus Gas Trust revenues on Blacktip Gas, MPAL's portion of a PWC contract settlement, offset by the 12.1% increase in the average exchange rate. This revenue stream ended as of June 30, 2011.

INVESTMENT AND OTHER INCOME DECREASED primarily as a result of a $2,065,000 realized gain on the sale of available-for-sale securities in the twelve months ended June 30, 2010.

COSTS AND EXPENSES

Changes in costs and expenses were as follows:

	TWELVE MONTHS ENDED June 30, 2011	2010	$ Variance	% Variance
Production costs	$ 9,247,199	$10,116,320	$ (869,121)	(9%)
Exploration and dry hole costs	2,853,832	1,273,268	1,580,564	124%
Salaries and employee benefits	5,079,503	4,816,350	263,153	5%
Depletion, depreciation and amortization	2,326,817	4,680,240	(2,353,423)	(50%)
Auditing, accounting and legal services	2,595,465	1,947,901	647,564	33%
Loss on Evans Shoal Deposit	15,892,650	—	15,892,650	*
(Gain) loss on sale of assets	(968,644)	(6,817,304)	5,848,660	(86%)
Impairment loss	173,401	2,049,616	(1,876,215)	(92%)
Other administrative expenses	7,285,549	6,030,583	1,254,966	21%
Warrant Expense	—	(4,276,471)	4,276,471	(100%)
Income tax provision	5,141,187	2,645,763	2,495,424	94%

* Not meaningful

Significant changes are discussed below.

PRODUCTION COSTS DECREASED due to the result of cost reductions efforts (Mereenie & Palm Valley) ($2,840,000) including a new transportation contract at Mereenie, the elimination of prior year pipeline repair costs at Mereenie, and the elimination of production costs related to the Cooper Basin Assets sold in fiscal year 2010 offset by the year over year effect of production costs associated with the U.S. assets acquired in October 2009 and March 2010 ($1,446,000) and the 12.1% increase in the average foreign exchange rate discussed below.

EXPLORATION AND DRY HOLE COSTS INCREASED at MPAL by $1,105,000, which was primarily due to drilling costs in the U.K. and 12.1% increase in the average foreign exchange rate discussed below. In the U.S., the $476,000 increase is associated with the U.S. assets acquired in October 2009 and March 2010.

SALARIES AND EMPLOYEE BENEFITS INCREASED due to current year severance payments in the U.S. to a former officer ($567,000) plus additional headcount, the year over year costs associated with the U.S. acquisition in October 2009 ($194,000), non-cash employee stock based compensation ($212,000) and the 12.1% increase in the average foreign exchange rate discussed below, offset by payment of employee termination costs in Australia in the prior year.

DEPLETION, DEPRECIATION AND AMORTIZATION DECREASED primarily because MPAL's Australia oil and gas assets were fully depleted as of September 30, 2010, resulting in reduced depletion for MPAL activity in the current year, offset by the costs associated with the U.S. assets acquired in October 2009 and March 2010 not present in the first three months of the twelve months ended June 30, 2010, and the 12.1% increase in the average foreign exchange rate discussed below.

AUDITING, ACCOUNTING AND LEGAL COSTS INCREASED primarily due to costs associated with the Evans Shoal transaction.

LOSS ON EVANS SHOAL DEPOSIT relates to the non-refundable deposit paid by MPAL to Santos as part of the Evans Shoal Transaction (See Note 12).

GAIN ON SALE OF ASSETS is mostly due to the sale of non-core assets that occurred primarily in the prior fiscal year. For more information on these sales please refer to Note 10 of our Form 10-K, Sale of Cooper Basin Assets footnote for the period ended June 30, 2010.

IMPAIRMENT LOSS relates to MPAL's loss on Udacha assets in the prior fiscal year and two remaining permits of the asset sale in the current year (See Notes 1 and 4).

OTHER ADMINISTRATIVE EXPENSES INCREASED primarily due to increased consulting fees at MPAL related to the Evans Shoal transaction, and 12.1% increase in the average foreign exchange rate discussed below.

WARRANT EXPENSE in the prior year relates entirely to the recording of the fair market value of certain warrants as discussed in our Form 10-K for the period ended June 30, 2010. The terms of the warrants were revised in March 2010 such that they are no longer carried at fair value.

INCOME TAX PROVISION INCREASED primarily due to net operating losses incurred in the current tax year that do not generate a corresponding tax benefit and the additional $7.0 million valuation allowance recorded against our Australian deferred tax assets. Deferred tax assets are recognized for the expected future tax consequences of temporary differences between the financial reporting and tax bases of assets and liabilities, and for operating losses and tax credit carryforwards. A valuation allowance reduces deferred tax assets to estimated realizable value, which assumes that it is more likely than not that we will be able to generate sufficient future taxable income in certain tax jurisdictions to realize the net carrying value. We review our deferred tax assets and valuation allowance on a quarterly basis. As part of our review, we consider positive and negative evidence, including cumulative results in recent years. As a result of our review for the quarter ended June 30, 2011, we provided for a full valuation allowance against our Australian deferred tax assets, in addition to our $7.0 million valuation allowance previously recorded against our U.S. deferred tax assets. This resulted in a material income tax charge.

We anticipate we will continue to record a valuation allowance against the losses of these jurisdictions until such time as we are able to determine it is "more-likely-than-not" the deferred tax asset will be realized. Such

Table of Contents

position is dependent on whether there will be sufficient future taxable income to realize such deferred tax assets. (see Note 7)

EXCHANGE EFFECT — the value of the Australian dollar relative to the U.S. dollar increased to 1.0591 at June 30, 2011 compared to a value of .8567 at June 30, 2010. This resulted in an $9,307,710 debit to the foreign currency translation adjustments account for the twelve months ended June 30, 2011. The average exchange rate used to translate MPAL's operations in Australia was .9893 for the the twelve months ended June 30, 2011, which was an 12.1% increase compared to the .8826 rate for the the twelve months ended June 30, 2010.

2010 vs. 2009

REVENUES AND INVESTMENT INCOME

Changes in revenues and investment income are as follows:

	TWELVE MONTHS ENDED June 30,			
	2010	2009	$ Variance	% Variance
Oil sales	$ 9,886,592	$11,479,660	$(1,593,068)	$ (14%)
Gas sales	13,615,755	14,740,296	(1,124,541)	(8%)
Other production related revenues	5,022,210	1,970,621	3,051,589	155%
Investment and other income	3,012,831	1,583,065	1,429,766	90%

Significant changes are discussed below.

OIL SALES DECREASED in Australia due to a 36% decrease in volume due to the sale of Cooper Basin assets and a 10% decrease in average price per barrel partially offset by the U.S. purchase of a controlling member interest in Nautilus Poplar, LLC and an 18% increase in the average exchange rate discussed below. Oil unit sales (after deducting royalties) in barrels (bbls) and the average price per barrel sold during the periods indicated were as follows:

	TWELVE MONTHS ENDED June 30,					
	2010 SALES		2009 SALES			
	BBLS	AVERAGE PRICE $ PER BBL	BBLS	AVERAGE PRICE $ PER BBL	% Variance BBLS	% Variance $ PER BBL
Australia (AUD):						
Mereenie field	68,344	$ 85.50	90,267	$ 94.20	(24%)	(9%)
Cooper Basin	1,086	83.62	2,362	101.42	(54%)	(18%)
Nockatunga project (1)	27,962	73.92	60,668	86.30	(54%)	(14%)
Total	97,392		153,297		(36%)	(10%)

	BBLS	AVERAGE PRICE $ PER BBL	BBLS	AVERAGE PRICE $ PER BBL	% Variance BBLS	% Variance $ PER BBL
United States:						
Poplar Field (1)	42,017	67.88	—	—	100%	100%

(1) Nockatunga average price per bbl is net of crude oil transportation costs which are deducted from the gross sales price.

Amounts presented above for oil prices and below for gas prices in Australia are in Australian dollars to show a more meaningful trend of underlying operations. For the fiscal years ended June 30, 2010 and 2009, the average foreign exchange rates were .8826 and .7471 respectively.

Table of Contents

GAS SALES DECREASED due to a 34% decrease in volume resulting from natural field decline and significantly reduced sales to PWC. PWC's most recent advisory to the Meerenie Producers (Magellan and Santos) states that Meerenie gas is no longer required, other than the reasonable endeavors obligation under the MSA No. 4 agreement to supply certain of PWC's requirements on request through September 5, 2010. For further information, see "Gas Supply Contracts" in Item 1 — Business and Item 7 — Management's Discussion and Analysis — Executive Summary, the decrease is partially offset by the 18% increase in the average exchange rate discussed below and by a 43% increase in the average price per mcf. The volumes in billion cubic feet (bcf) (after deducting royalties) and the average price of gas per thousand cubic feet (mcf) sold during the periods indicated were as follows:

	TWELVE MONTHS ENDED June 30,					
	2010 SALES		2009 SALES			
	BCF	AVERAGE PRICE AUD $ PER MCF	BCF	AVERAGE PRICE AUD $ PER MCF	% Variance BCF	% Variance AUD $ PER MCF
Australia: Palm Valley	1.166	2.25	1.165	2.25	— %	— %
Australia: Mereenie	2.264	6.53	3.996	3.93	(43%)	66%
Total	3.430	5.07	5.161	3.54	(34%)	43%

OTHER PRODUCTION RELATED REVENUES are primarily MPAL's share of gas pipeline tariff revenues which increased as a result of an increase in Amadeus Gas Trust revenues on Blacktip Gas. MPAL's portion of a PWC contract settlement, and the 18% increase in average exchange rate.

INVESTMENT AND OTHER INCOME increased primarily due to an investment gain.

COSTS AND EXPENSES

Changes in costs and expenses were as follows:

	TWELVE MONTHS ENDED June 30,			
	2010	2009	$ Variance	% Variance
Production costs	10,116,320	8,153,263	1,963,057	24%
Exploration and dry hole costs	1,273,268	3,475,937	(2,202,669)	(63%)
Salaries and employee benefits	4,816,350	1,708,997	3,107,353	182%
Depletion, depreciation and amortization	4,680,240	6,785,952	(2,105,712)	(31%)
Auditing, accounting and legal services	1,947,901	1,576,509	371,392	24%
Accretion expense	748,209	531,405	216,804	41%
(Gain) Loss on sale of assets	(6,817,304)	12,072	(6,829,376)	(56,572%)
Impairment loss	2,049,616	63,740	1,985,876	3,116%
Other administrative expenses	6,030,583	3,018,200	3,012,383	100%
Foreign transaction (gain) loss	676,601	951,458	(274,857)	(29%)
Warrant Expense	4,276,471	—	4,276,471	*
Income tax provision	2,645,763	2,198,422	447,341	20%

* Not meaningful

Significant changes are discussed below.

PRODUCTION COSTS INCREASED due primarily to the acquisition of a controlling member interest in the Poplar Fields ($1,446,000) along with the 18% increase in the average exchange rate described below partially offset by the sale of the Cooper Basin assets (see Note 10).

EXPLORATION AND DRY HOLE COSTS DECREASED primarily due to prior year's cost of ($300,000) related to the write down of the value of U.K. exploration licenses, seismic survey costs related to the Nockatunga fields ($1.6 million), and the sale of Cooper Basin assets (see Note 10). These costs are partially offset by the 18% increase in the average exchange rate described below.

SALARIES AND EMPLOYEE BENEFITS INCREASED mostly due to the payment of employee termination costs ($883,000) at MPAL, non cash expense related to awarded of employee stock options ($1,400,000), the addition of new personnel at MPC ($338,000), the Nautilus acquisition ($331,000) and the 18% increase in the average exchange rate.

DEPLETION, DEPRECIATION AND AMORTIZATION DECREASED due to lower depletable costs related to the Cooper Basin assets sales (see Note 10), partially offset by the 18% increase in the average exchange rate described below and the acquisition of Nautilus ($448,000).

AUDITING, ACCOUNTING AND LEGAL SERVICES INCREASED due mostly to legal and accounting costs associated with the Nautilus acquisition, consulting fees related to the Evans Shoal transaction, and the 18% increase in the average exchange rate discussed below.

ACCRETION EXPENSE INCREASED due mostly to the controlling member interest in the Poplar Fields ($70,000) along with the 18% increase in the average exchange rate.

(GAIN) LOSS ON THE SALE OF ASSETS INCREASED due to the 2010 gain recorded on the sale of MPAL'S Cooper Basin assets ($6.8 million) (see Note 10).

IMPAIRMENT LOSS INCREASED due mostly to the impairment loss recorded on MPAL's Udacha, Dingo and some UK assets (see Note 4).

OTHER ADMINISTRATIVE EXPENSES INCREASED due to costs relating to the July 2009 closing of the YEP equity-investment ($440,000), increased travel costs ($308,000), increased directors' fees including the addition of three new directors ($250,000), Board of Director stock options ($103,000), Board of Directors Restricted Stock ($405,000), increased consulting costs ($725,000), closing costs for the Nautilus acquisition ($138,000) and the 18% increase in the average exchange rate described below.

FOREIGN TRANSACTION (GAIN) LOSS account represents transaction gains and losses that result from the translation of cash accounts held in foreign currencies.

WARRANT EXPENSE INCREASED (non-cash) due entirely to the increase in the fair value of the YEP warrants, which was driven by increases in the Company's stock price. These warrants did not exist in 2009.

INCOME TAX PROVISION INCREASED due to the taxability in the U.S. of intercompany dividends which were not completely offset by available net operating loss carry forwards and nondeductible warrant and stock related compensation, offset by a decrease in Australian taxes due to the non-taxability of certain capital receipts (see Note 7). The effective tax rate of 223% results from the fact that MPC book losses do not generate a corresponding tax benefit because the taxable intercompany dividends and the nondeductible warrant and stock related compensation exceed book losses and thus create taxable income.

EXCHANGE EFFECT — the value of the Australian dollar relative to the U.S. dollar increased to $.8567 at June 30, 2010 compared to $.8048 at June 30, 2009. This resulted in a $1,358,464 credit to accumulated translation adjustments for fiscal 2010. The annual average exchange rate used to translate MPAL's operations in Australia for fiscal 2010 was $.8826, which is an 18% increase compared to the $.7471 rate for fiscal 2009.

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 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 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. A 10% change in the Australian foreign currency rate compared to the U.S. dollar would increase or decrease revenues and costs and expenses by approximately $1.8 million and $3.6 million, respectively, for the twelve months ended June 30, 2011.

For the twelve months ended June 30, 2011, oil sales represented approximately 87% of total oil and gas revenues. Based on the current twelve month’s 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 13% of total oil and gas revenues in the current twelve months, are derived primarily from the Palm Valley 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, 2011.

At June 30, 2011, the carrying value of cash and cash equivalents was approximately $20.4 million, which approximates the fair value.

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
Portland, Maine

We have audited the accompanying consolidated balance sheets of Magellan Petroleum Corporation and subsidiaries (the "Company") as of June 30, 2011 and 2010, and the related consolidated statements of operations, changes in equity and comprehensive loss, and cash flows for each of the three years in the period ended June 30, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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 consolidated financial statements present fairly, in all material respects, the financial position of Magellan Petroleum Corporation and subsidiaries as of June 30, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, on June 30, 2010, the Company adopted Accounting Standards Update No. 2010-3, "*Oil and Gas Reserve Estimation and Disclosures*".

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated September 20, 2011 expressed an adverse opinion on the Company's internal control over financial reporting because of material weaknesses.

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

MAGELLAN PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

	June 30, 2011	June 30, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,416,625	$ 33,591,534
Accounts receivable — trade (net of allowance for doubtful accounts of $66,702 and $95,912 at June 30, 2011 and at June 30, 2010 respectively)	4,356,621	4,427,245
Accounts receivable — working interest partners	453,843	204,630
Deposit on Evans Shoal	10,745,061	—
Securities available-for-sale (at fair value)	—	192,417
Inventories	731,672	815,179
Deferred income taxes	—	189,236
Assets held for sale	—	648,217
Prepaid assets	517,482	478,665
Other assets	61,934	1,223,426
Total current assets	37,283,238	41,770,549
Deferred income taxes	—	5,262,649
Securities available-for-sale (at fair value)	238,070	—
Deposit on Evans Shoal	—	12,850,500
Property and equipment, net:		
Oil and gas properties (successful efforts method)	138,576,622	113,646,852
Land, buildings and equipment	4,088,759	3,328,670
Field equipment	6,390,383	5,843,939
	149,055,764	122,819,461
Less accumulated depletion, depreciation and amortization	(119,901,581)	(96,905,478)
Net property and equipment	29,154,183	25,913,983
Goodwill	4,695,204	4,695,204
Other assets	204,457	213,500
Total assets	$ 71,575,152	$ 90,706,385
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,860,919	$ 2,387,857
Accrued liabilities	2,056,717	2,064,979
Demand notes payable	500	470,000
Current portion of note payable	552,000	451,585
Liability related to assets held for sale	—	194,465
Deferred income taxes	—	83,400
Income taxes payable	—	460,617
Total current liabilities	6,470,136	6,112,903
Long term liabilities:		
Deferred income taxes	—	1,157,735
Note payable	870,438	232,430
Other long term liabilities	309,758	92,577
Asset retirement obligations	11,397,410	9,292,556
Total long term liabilities	12,577,606	10,775,298
Commitments and contingencies (Note 16)	—	—
Equity:		
Common stock, par value $.01 per share: Authorized 300,000,000 shares, outstanding, 52,455,977 and 52,335,977 at June 30, 2011 and June 30, 2010 respectively	524,558	523,358
Capital in excess of par value	93,617,424	91,905,062
Preferred stock, par value $.01 per share: Authorized 50,000,000 and 0 shares, outstanding, none at June 30, 2011 and at June 30, 2010 respectively	—	—
Accumulated deficit	(56,073,255)	(23,640,191)
Accumulated other comprehensive income	12,469,626	3,116,263
Total equity attributable to Magellan Petroleum Corporation	50,538,353	71,904,492
Non-controlling interest in subsidiaries	1,989,057	1,913,692
Total equity	52,527,410	73,818,184
Total liabilities and equity	$ 71,575,152	$ 90,706,385

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

Table of Contents

MAGELLAN PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
Three Years Ended June 30, 2011

	Years Ended June 30, 2011	2010	2009
Revenues:			
Oil sales	$ 11,815,231	$ 9,886,592	$11,479,660
Gas sales	1,796,405	13,615,755	14,740,296
Other production related revenues	4,565,241	5,022,210	1,970,621
Total revenues	18,176,877	28,524,557	28,190,577
Costs and expenses:			
Production costs	9,247,199	10,116,320	8,153,263
Exploration and dry hole costs	2,853,832	1,273,268	3,475,937
Salaries and employee benefits	5,079,503	4,816,350	1,708,997
Depletion, depreciation and amortization	2,326,817	4,680,240	6,785,952
Auditing, accounting and legal services	2,595,465	1,947,901	1,576,509
Accretion expense	563,628	748,209	531,405
Loss on Evans Shoal Deposit	15,892,650	—	—
Shareholder communications	396,092	551,408	633,112
(Gain) loss on sale of assets	(968,644)	(6,817,304)	12,072
Impairment loss	173,401	2,049,616	63,740
Other administrative expenses	7,285,549	6,030,583	3,018,200
Foreign transaction loss	950,671	676,601	951,458
Total costs and expenses	46,396,163	26,073,192	26,910,645
Operating (loss) income	(28,219,286)	2,451,365	1,279,932
Warrant expense	—	(4,276,471)	—
Investment and other income	922,774	3,012,831	1,583,065
(Loss) income before income taxes	(27,296,512)	1,187,725	2,862,997
Income tax provision	5,141,187	2,645,763	2,198,422
Net (loss) income	(32,437,699)	(1,458,038)	664,575
Less net (loss) income attributable to non-controlling interest in subsidiaries	(4,635)	(10,766)	—
Net (loss) income attributable to Magellan Petroleum Corporation	$(32,433,064)	$ (1,447,272)	$ 664,575
Average number of shares of common stock			
Basic and Dilutive	52,398,936	51,410,596	41,500,325
Net (loss) income per basic and dilutive common shares attributable to Magellan Petroleum Corporation common shareholders	$ (0.62)	$ (0.03)	$ 0.02

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

MAGELLAN PETROLEUM CORPORATION

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY AND COMPREHENSIVE LOSS
Three Years Ended June 30, 2011

	Number of Shares	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Non-controlling interest	Total	Total Comprehensive Income (Loss)
June 30, 2008	41,500,325	415,001	73,216,143	(22,857,494)	11,689,777	—	62,463,427	
Net income	—	—	—	664,575	—	—	664,575	664,575
Foreign currency translation adjustments	—	—	—	—	(9,931,978)	—	(9,931,978)	(9,931,978)
Unrealized holding gains, net of taxes	—	—	—	—	221,964	—	221,964	221,964
Stock and stock based compensation	—	—	94,932	—	—	—	94,932	
Total comprehensive loss	—	—	—	—	—	—		(9,045,439)
June 30, 2009	41,500,325	415,001	73,311,075	(22,192,919)	1,979,763	—	53,512,920	
Net loss	—	—	—	(1,447,272)	—	(10,766)	(1,458,038)	(1,458,038)
Foreign currency translation adjustments	—	—	—	—	1,358,464	—	1,358,464	1,358,464
Unrealized holding gains, net of taxes	—	—	—	—	(221,964)	—	(221,964)	(221,964)
Stock and stock based compensation	440,000	4,400	2,301,352	—	—	—	2,305,752	
Equity investment YEP	8,695,652	86,957	7,527,870	—	—	—	7,614,827	
Warrants issued	—	—	6,401,765	—	—	—	6,401,765	
Nautilus acquisition	1,700,000	17,000	2,363,000	—	—	1,924,458	4,304,458	
Total comprehensive loss	—	—	—	—	—	—	—	(321,538)
June 30, 2010	52,335,977	523,358	91,905,062	(23,640,191)	3,116,263	1,913,692	73,818,184	
Net loss	—	—	—	(32,433,064)	—	(4,635)	(32,437,699)	(32,437,699)
Foreign currency translation adjustments	—	—	—	—	9,307,710	—	9,307,710	9,307,710
Unrealized holding gains, net of taxes	—	—	—	—	45,653	—	45,653	45,653
Stock and stock based compensation	90,000	900	1,669,162	—	—	—	1,670,062	
Stock options exercised	30,000	300	43,200	—	—	—	43,500	
Capital contribution						80,000	80,000	
Total comprehensive loss	—	—	—	—	—		—	(23,084,336)
June 30, 2011	52,455,977	524,558	93,617,424	(56,073,255)	12,469,626	1,989,057	52,527,410	

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

MAGELLAN PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended June 30,		
	2011	2010	2009
Operating Activities:			
Net (loss) income	$ (32,437,699)	$ (1,458,038)	$ 664,575
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:			
Depletion, depreciation and amortization	2,326,817	4,680,240	6,785,952
Write off of Evans Shoal deposit	15,892,650	—	—
Interest earned on restricted deposits	(149,961)	—	—
Accretion expense	563,628	748,209	531,405
Deferred income taxes	5,354,748	921,934	(1,618,033)
Foreign transaction loss (1)	498,957	732,091	951,458
(Gain) loss from disposal of assets	(968,644)	(6,817,304)	12,072
(Gain) from sale of investments	—	(1,975,286)	—
Exploration and dry hole costs	(123,970)	—	5,765
Write off of exploration permits	66,098	—	359,471
Impairment loss	173,401	2,049,616	—
Stock-based compensation and change in warrant valuation	1,670,062	6,582,223	94,932
Change in operating assets and liabilities:			
Accounts receivable	622,779	2,734,772	1,270,721
Inventories	142,745	646,986	203,312
Other assets	212,894	(105,952)	65,531
Accounts payable and accrued liabilities	613,981	(1,689,063)	1,793,486
Income taxes payable (receivable)	1,044,968	(3,097,915)	(930,137)
Net cash (used in) provided by operating activities (1)	(4,496,546)	3,952,513	10,190,510
Investing Activities:			
Additions to property and equipment	(729,849)	(2,276,128)	(2,430,184)
Oil and gas exploration activities	(3,837,775)	(567,343)	(491,490)
Proceeds from sale of assets	1,481,172	7,280,402	27,728
Purchase of working interest in Poplar Field	(380,000)	(4,090,170)	—
Deposit for purchase of Evans Shoal	(10,013,500)	(13,751,850)	—
Proceeds from sale of securities available for sale	—	9,615,215	—
Purchase of securities available for sale	—	(7,259,082)	(559,850)
Proceeds from sale of securities	—	465,004	—
Marketable securities matured or sold	6,999,735	7,194,090	3,109,611
Marketable securities purchased	(6,999,735)	(6,196,784)	(2,398,695)
Purchase of controlling interest — Nautilus Poplar LLC	—	(7,309,113)	—
Cash acquired-purchase of Nautilus Poplar LLC	—	314,727	—
Increase in restricted cash	—	(75,444)	—
Net cash (used) in investing activities	(13,479,952)	(16,656,476)	(2,742,880)
Financing Activities:			
Proceeds from issuance of stock	43,500	10,000,000	—
Proceeds from borrowings	5,027,323	570,000	—
Debt principal payments	(4,589,053)	(845,147)	—
Non-controlling Capital Contribution — Nautilus Poplar LLC	80,000	—	—
Equity issuance costs	—	—	(259,879)
Net cash by (used in) provided by financing activities	561,770	9,724,853	(259,879)
Effect of exchange rate changes on cash and cash equivalents (1)	4,239,819	1,881,802	(7,114,137)
Net increase in cash and cash equivalents	(13,174,909)	(1,097,308)	73,614
Cash and cash equivalents at beginning of period	33,591,534	34,688,842	34,615,228
Cash and cash equivalents at end of year	$ 20,416,625	$ 33,591,534	$ 34,688,842
Cash Payments:			
Income taxes	(1,258,529)	4,821,744	4,746,589
Interest Paid, net of amount capitalized	140,656	62,300	—
Supplemental Schedule of Noncash Investing and Financing Activities:			
Unrealized holding gain (loss)	45,652	—	344,074
Revision to estimate of asset retirement obligations	(128,805)	(2,231,849)	(625,962)
Accounts payable related to property and equipment	7,852	48,029	163,457

(1) See Note 2 for explanation of Restatement of Prior Period Amount

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

1. Summary of Significant Accounting Policies

Principles of Consolidation

Magellan Petroleum Corporation (the "Company" or "Magellan" or "MPC" or "we" or "us") is engaged in the sale of oil and gas and the exploration for and development of oil and gas reserves. At June 30, 2011, MPC had three reporting segments: (1) the 100.00% equity interest in its subsidiary, Magellan Petroleum Australia Limited ("MPAL"). MPAL's major assets are two petroleum production leases covering the Mereenie oil and gas field (35% working interest), one petroleum production lease covering the Palm Valley gas field (52% working interest) and thirteen licenses in the United Kingdom, five of which are operating licenses. Both the Mereenie and Palm Valley fields are located in the Amadeus Basin in the Northern Territory of Australia; (2) an 83.5% controlling member interest in Nautilus Poplar, LLC ("Nautilus"), based in Denver, Colorado and (3) MPC the parent company, which owns directly a 28.3% working interest in the Poplar Fields in Montana. On a consolidated basis, MPC through Nautilus owned an average 85.7% working interest in the Poplar Fields in Montana as of June 30, 2011.

During the year ended June 30, 2010, MPC added to its holdings, its 83.5% controlling member interest in Nautilus and a 26.3% average working interest in the Poplar fields. During the year ended June 30, 2011, MPC added an additional 2% to its working interest giving MPC 85.7% of the total working interest of the consolidated group in the Poplar Field.

Nautilus, based in Denver, Colorado, operates and holds a 68.75% interest in the East Poplar Unit and varied interests averaging 57% in the Northwest Poplar Field in Montana, USA.

MPC has a direct 2.67% carried interest in the Kotaneelee gas field in the Yukon Territory of Canada.

The accompanying consolidated financial statements include the accounts of MPC and its subsidiaries, MPAL and Nautilus, (collectively the "Company"). All intercompany transactions have been eliminated.

Reclassification

Certain reclassifications of prior period data included in the accompanying Consolidated Statement of Operations and Consolidated Balance Sheets have been made to conform to current financial statement presentation. Foreign currency exchange (gains) losses of $676,601 and $951,458 for the twelve months ended June 30, 2010 and June 30, 2009, respectively, were reclassified from other administrative expenses to foreign transaction losses on the consolidated statements of operations. This reclassification did not impact previously reported operating or net income. Prepaid assets of $478,665 at June 30, 2010 were reclassified from other current assets.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Revenue Recognition

The Company recognizes oil and gas revenue (net of royalties) from its interests in producing wells as oil and gas is produced and sold from those wells. Revenues from the sale and transportation of natural gas are recognized upon completion of the sale and when transported volumes are delivered. Other production related revenues are primarily MPAL's share of gas pipeline tariff revenues which are recorded at the time of sale. The Company records pipeline tariff revenues on a gross basis with the revenue included in other production related revenues and the remittance of such tariffs are included in production costs. Government sales taxes related to MPAL's oil and gas production revenues are collected by MPAL and remitted to the Australian government. Such amounts are excluded from revenue and expenses. Shipping and handling costs in connection with the MPAL deliveries are included in production costs. Revenue under carried interest agreements is recorded in the period when the net proceeds become receivable, measurable and collection is reasonably assured. The time when the net revenues become receivable and collection is reasonably assured depends on the terms and conditions of the relevant agreements and the practices followed by the operator. Other production revenues for the twelve months ended June 30, 2010 also included MPAL's share of Power and Water Corporation (PWC) contract settlement for a breach in their gas contracts in the amount of $1.0 million.

Trade receivables

Collectability of trade receivables is reviewed on an ongoing basis. Receivables which are known to be uncollectible are written off by reducing the carrying amount directly. An allowance for doubtful accounts is used when there is objective evidence that the Company will not be able to collect all amounts due, according to the original terms of the related sales. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the trade receivable is not collectable. The amount of bad debt expense is recognized in the income statement within other administrative expenses. When a trade receivable, for which an allowance had been recognized, becomes uncollectible in a subsequent period, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against other administrative expenses in the consolidated statement of operations.

Preferred Stock

On December 8, 2010, shareholders approved an amendment to the Company's Restated Certificate of Incorporation to authorize a class of 50,000,000 shares of preferred stock, par value of $0.01 per share ("Preferred Stock"). Pursuant to the amendment, shares of Preferred Stock may be issued in one or more series of any number of shares as determined by the Company's Board of Directors ("Board"). The Board may fix the voting powers of such series and the designations, preferences, relative, participating, optional or other special rights, and the qualifications, limitations or restrictions thereof (including such series' redemption rights, dividend rights, liquidation preferences, and conversion rights). As of June 30, 2011, no preferred shares have been issued.

Stock-Based Compensation

The Company has one stock incentive plan which was amended on December 8, 2010 to increase the aggregate number of shares issuable under the plan to 7,205,000. The costs resulting from all share-based payment transactions are recognized in the consolidated financial statements. GAAP establishes fair value as the measurement objective in accounting for share-based payments with employees and non-employees. The Company uses the Black-Scholes option valuation model to determine the fair value of its time based stock option share awards and the Monte Carlo model for performance based options share awards that include a market condition. These models include various assumptions, including the expected volatility and the expected life of the share awards as well as significant assumptions for performance based awards that include probabilities of certain vesting conditions and behaviors impacting exercise. These assumptions, as detailed in Note 6 reflect the Company's best estimates, but they involve inherent uncertainties based on market conditions generally outside of the control of the Company. As a result, if other assumptions had been used, stock-based compensation expense, as calculated and recorded could have been significantly impacted. Furthermore, if the Company uses different assumptions in future periods, stock-based compensation expense could be significantly impacted in future periods. The Company's policy for attributing the value of graded vested share-based payments is an accelerated multiple-option approach.

Concentration of Credit Risk

The Company's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents. The Company places 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.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for its oil and gas operations. Under this method, the costs of successful wells, development dry holes, productive leases, and permit and concession costs 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. The Company records its proportionate share in joint venture operations in the respective classifications of assets, liabilities and expenses. Unproved properties with significant acquisition costs are periodically assessed for impairment in value, with any 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 are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The Company estimates the future undiscounted cash flows from the affected properties to determine the recoverability of carrying amounts. In general, analyses are based on proved developed reserves for gas, except in the case of Palm Valley proved gas, which is based in contracted volumes. At June 30, 2011, Mereenie had no gas contracts, thus no gas reserves. For Palm Valley, reserves were based upon the quantities of gas committed to the existing contract and estimated sales subsequent to the contract date. If such contracts are extended, the proved developed reserves will be increased to the lesser of the actual proved developed reserves and risk adjusted probable and possible reserves or the contracted quantities.

Exploratory drilling costs are initially capitalized pending determination of proved reserves but are charged to expense if no proved reserves are found. Other exploration costs, including geological and geophysical expenses, leasehold expiration costs and delay rentals, are expensed as incurred. Because the Company follows the successful efforts method of accounting, the results of operations may vary materially from quarter to quarter. An active exploration program may result in greater exploration and dry hole costs.

Table of Contents

Nondepletable assets

At June 30, 2011, 2010 and 2009 oil and gas properties include $8.1 million, $4.3 million and $6.6 million, respectively, of capitalized costs that are currently not being depleted pending the determination of proved reserves. Components of these costs are as follows:

Nondepletable capitalized assets	2011	2010	2009
United Kingdom (1)			
Balance beginning of year	$3,576,518	$ 3,154,266	$2,978,172
Additions to capitalized costs	1,703,285	608,479	485,725
Assets sold or held for sale	—	—	—
Reclassified to producing properties	—	—	—
Charged to expense	35,814	(231,798)	(257,519)
Exchange adjustment	(55,892)	45,571	(52,112)
Balance end of year	$5,259,725	$ 3,576,518	$3,154,266
United States (2)			
Balance beginning of year	$ 313,710	$ —	$ —
Additions to capitalized costs	2,406,210	313,710	—
Assets sold or held for sale	—	—	—
Reclassified to producing properties	(277,417)	—	—
Charged to expense	(31,934)	—	—
Exchange adjustment	—	—	—
Balance end of year	$2,410,569	$ 313,710	$ —
Australia (3)			
Balance beginning of year	$ 415,108	$ 3,486,611	$3,852,698
Additions to capitalized costs	—	—	—
Assets sold or held for sale	—	(3,071,503)	—
Reclassified to producing properties	—	—	—
Charged to expense	—	—	(63,739)
Exchange adjustment	—	—	(302,348)
Balance end of year	$ 415,108	$ 415,108	$3,486,611
Total			
Balance beginning of year	$4,305,336	$ 6,640,877	$6,830,870
Additions to capitalized costs	4,109,495	922,189	485,725
Assets sold or held for sale	—	(3,071,503)	—
Reclassified to producing properties	(277,417)	—	—
Charged to expense	3,880	(231,798)	(321,258)
Exchange adjustment	(55,892)	45,571	(354,460)
Balance end of year	$8,085,402	$ 4,305,336	$6,640,877

(1) Of this amount, $1.9 million relates to the stepped up value of the U.K exploration permits and licenses, which was recorded in the 2006 acquisition of the 44.87% remaining interest of MPAL. The step up value of these licenses and permits are evaluated annually. The balance represents capitalized exploratory well costs, initiated in 2007, pending discovery and production of reserves.

(2) U.S. capitalized exploratory well costs initiated in 2010, pending discovery and production of reserves.

(3) The balance at June 30, 2011 relates to an exploration permit held by MPAL related to step up to fair value for the 44.87% remaining interest of MPAL acquired in 2006, which is evaluated for impairment annually or when events or changes in circumstances indicate. During the fiscal year ended June 30, 2010, Cooper Basin assets were sold. Prior costs were capitalized during the fiscal year ended June 30, 2006 and remained capitalized through the date of the sale as the related well had a sufficient quantity of reserves to justify its completion as a producing well.

Goodwill

The aggregate amount of goodwill is $4,695,204 at June 30, 2011 and 2010, of which $4,020,706 is related to the fiscal 2006 acquisition of the 44.87% of MPAL that we did not own at the time and $674,500 is attributable to the October 15, 2009 acquisition of Nautilus.

Goodwill is not amortized but is tested for impairment annually or whenever events or changes in circumstances indicate that the carrying value may be impaired. Our annual impairment testing date for MPAL related goodwill is June 30 and is October 1 for Nautilus.

Goodwill is tested for impairment using a two-step process.

- Step one — the fair value of each reporting unit is compared to its carrying value in order to identify potential impairment. If the fair value of a reporting unit exceeds the carrying value of its net assets, goodwill is not considered impaired and no further testing is required. If the carrying value of the net assets exceeds the fair value of a reporting unit, potential impairment is indicated and step two of the impairment test is performed in order to determine the implied fair value of the reporting unit's goodwill and measure the potential impairment loss.
- Step two — when potential impairment is indicated in step one, we compare the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. Determining the implied fair value of goodwill requires a valuation of the reporting unit's tangible and intangible assets and liabilities in a manner similar to the allocation of the purchase price in a business combination. Any excess of the value of a reporting unit over the amounts assigned to its assets and liabilities is referred to as the implied fair value of goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. At June 30, 2011, Magellan passed step one and therefore the Company concluded step two was not necessary, as no impairment existed.

Determining the fair value of a reporting unit involves the use of significant estimates and assumptions.

We employed the adjusted net assets method to estimate the fair value of MPAL at June 30, 2011. This method entails estimating the fair value of all of MPAL's balance sheet items as of the valuation date. The Company has utilized the Market Approach, specifically the Similar Transaction Method ("STM") in order to estimate the fair value of MPAL's acreage and oil and natural gas reserves (collectively, the "MPAL Reserves") on the balance sheet. The MPAL Reserves are reflected on the balance sheet as Oil and gas Properties. This line includes Exploration Phase petroleum properties (i.e. exploratory acreage) and Production Phase petroleum properties (i.e. proved and probable oil and natural gas reserves). In its application of the STM, the Company reviewed publicly available transaction data for the sale of comparable resources in the U.K. and Australia in order to estimate the fair value of MPAL Reserves. If the adjusted equity value, after considering the fair values of the assets and liabilities, is greater than the carrying value of MPAL, then no impairment is indicated. Management believes that this methodology is most meaningful since the highest and best use of these assets would be to continue to hold and exploit the assets over time. No impairment existed as the adjusted fair value exceeded the carrying value as of June 30, 2011.

The fair value of our oil properties are estimated using a form of the market approach, which consists of a review of similar transactions that have occurred in the marketplace for proved and risk adjusted probable and possible reserves. Accordingly, we have reviewed implied prices per thousand cubic feet equivalent associated with market-based transactions in similar geographic locations for each of our oil properties, and selected appropriate metrics based on a qualitative comparison between our oil properties and the relevant transactions.

The fair value of our non-depletable exploration permits and licenses is estimated based on a review of similar transactions that have occurred in the marketplace. Accordingly, we have reviewed implied prices per acre associated with market-based transactions in similar geographic locations for our non-depletable exploration permits and licenses, and selected appropriate metrics based on a qualitative comparison between our non-depletable exploration permits and the relevant transactions.

At October 1, 2010, we performed our annual impairment test of the Nautilus goodwill. We employed both the income approach (discounted cash flow method) and the market value approach in estimating the fair value of Nautilus. As of October 1, 2010, no impairment existed as the indicated fair value of Nautilus, based upon our estimate, exceeded its carrying value as of October 1, 2010.

Asset Retirement Obligations

Obligations associated with the retirement of long-lived assets are recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset (oil and gas properties) and amortized on a units-of-production basis over the life of the related reserves. Accretion expense in connection with the discounted liability is recognized over the remaining life of the related liability.

The estimated liability is based on the future estimated cost of land reclamation, plugging the existing oil and gas wells and removing the surface facilities equipment in Australia and the U.S. The liability is a discounted liability using a credit-adjusted risk-free rate on the date such liabilities are determined. Revisions to the liability could occur due to changes in the estimated life of the field, estimates of these costs, acquisition of additional properties and as new wells are drilled.

Land, Buildings and Equipment and Field Equipment

Land, buildings and equipment and Field equipment are carried at cost. Depreciation and amortization are provided on a straight-line basis over their estimated useful lives. The estimated useful lives are: buildings — 40 years, equipment and field equipment — 3 to 15 years.

Inventories

Inventories consist of crude oil in various stages of transit to the point of sale and are valued at the lower of cost (determined on an average cost basis) or market. Inventories at Nautilus also include parts inventory using the first in-first out (FIFO) method.

Foreign Currency Translations

The accounts of MPAL, whose functional currency is the Australian dollar, are translated into U.S. dollars. The translation adjustment is included in accumulated other comprehensive income (loss), which is a component of equity, whereas gains or losses on foreign currency transactions are included in the determination of income. All assets and liabilities are translated at the rates in effect at the balance sheet dates. Revenues, expenses, gains and losses are translated using quarterly weighted average exchange rates during the period. At June 30, 2011 and 2010, the Australian dollar was equivalent to U.S. 1.0595 and .8567, respectively. The annual weighted average exchange rates ($AUD to $USD) used to translate MPAL's operations in Australia for the fiscal years 2011, 2010, and 2009 were .9893, .8826, and .7471, respectively.

The accounts of MPAL's U.K. division, whose functional currency is the British pound, are translated into Australian dollars before MPAL consolidates. The translation adjustment is included in accumulated other comprehensive income (loss), whereas gains or losses on foreign currency transactions are included in the determination of income. All assets and liabilities are translated at the rates in effect at the balance sheet dates. Revenues, expenses, gains and losses are translated using quarterly weighted average exchange rates during the period.

Accrued Liabilities

At June 30, 2011 and 2010, balances in accrued liabilities which exceeded 5% of current liabilities include $1,011,623 and $766,317 of employment benefits, respectively, and $-0- and $356,812 of withholding and sale taxes, respectively.

Accounting for Income Taxes

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 is 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 is greater than 50 percent likely 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 fiscal 2011 and 2010.

The Company has adopted an accounting policy to record all tax related interest and penalties in its tax provision calculation.

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.

Cash and Cash Equivalents

The Company considers all highly liquid short term investments with maturities of three months or less at the date of acquisition to be cash equivalents. The components of cash and cash equivalents are as follows:

	June 30,	
	2011	**2010**
Cash	$14,037,404	$18,030,155
Australian time deposit accounts without restriction	6,379,221	15,561,379
	$20,416,625	$33,591,534

Commonwealth Bank holds 60% of the cash and cash equivalent balance.

Marketable Securities

The Company's marketable securities are held-to-maturity securities and are carried at amortized costs. At June 30, 2011 and June 30, 2010, MPC had no marketable securities.

Securities Available-for-Sale

The Company classifies equity securities that have a readily determinable fair value and are not bought and not held principally for the purpose of selling them in the near term as securities available-for-sale. Unrealized holding gains and losses for available-for-sale securities are excluded from earnings and reported in other comprehensive income until realized. The Company had $238,070 and $192,417 in securities classified as available for sale at June 30, 2011 and June 30, 2010, respectively.

At June 30, 2011, the Company recorded an unrealized gain of $45,653 included in accumulated other comprehensive income.

At June 30, 2010, the Company realized a loss of $90,083 included in earnings on these securities as they were intended to be sold in the next quarter. Therefore the amount of net unrealized holding losses that had been included in accumulated other comprehensive income was $0 for securities available-for-sale for the twelve months ended June 30, 2010.

During the twelve months ended June 30, 2010, the Company received proceeds of $2,648,278, upon the sale of available-for-sale equity securities. The gain on sale was calculated on a last-in-first-out basis. Realized gains of $2,065,369 for the twelve months ended June 30, 2010 were included in earnings for these securities sold during fiscal year ended June 30, 2010. The amount of unrealized holding gains for the twelve months ended June 30, 2010 that was reclassified out of accumulated other comprehensive income into earnings and included in the gain on sale is $221,964.

Business combinations

The Company applies the acquisition method of recording business combinations. Under this method, the Company recognizes and measures the identifiable assets acquired, the liabilities assumed 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.

(Loss) Earnings per Share

(Loss) earnings 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 non-vested shares. The potential dilutive impact of non-vested shares is determined using either the treasury stock method or the two-class method, whichever leads to higher dilution. The dilutive impact of stock options and warrants is determined using the treasury stock method.

At June 30, 2011, the Company had 9,297,826 options and warrants outstanding that had an exercise price below the average stock price for the period that resulted in 3,460,331 incremental dilutive shares for the period. The Company also had outstanding 104,167 non-vested shares of company stock that were non-dilutive at June 30, 2011. There were no other potentially outstanding items at June 30, 2011. Due to the current period loss, all of the above are anti-dilutive.

In fiscal 2011, the Company issued 1,750,000 stock options, and 400,000 were forfeited in the same year. See Note 6.

At June 30, 2010, the Company had outstanding 8,127,826 options and warrants that had an exercise price below the average stock price for the period that resulted in 1,634,797 incremental dilutive shares for the respective periods. Due to the net loss, all items are anti-dilutive. The Company also had 208,334 non-vested shares of company stock that are anti-dilutive at June 30, 2010. There were no other potentially dilutive items at June 30, 2010.

In 2010, the Company issued 637,500 stock options, 4,347,826 warrants and 350,000 non-vested shares. An additional 700,000 stock options were awarded on April 1, 2010 were subject to shareholder approval, which was obtained December 8, 2010. As this approval was pending, there was no grant date for accounting purposes and, consequently, there was no financial statement impact during the year ended June 30, 2010. (See Note 6)

Accumulated Other Comprehensive Income

Accumulated other comprehensive income at June 30, 2011 and 2010 was as follows:

	2011	2010
Foreign currency translation adjustments	$12,423,973	$3,116,263
Unrealized holding gains, net of deferred tax	45,653	—
Accumulated other comprehensive income	$12,469,626	$3,116,263

Investment and Other Income

Investment and other income at June 30, 2011, 2010 and 2009 was as follows:

	2011	2010	2009
Investment income	$922,774	$3,012,831	$1,583,065
Other income	—	—	—
Investment and other income	$922,774	$3,012,831	$1,583,065

Warrants

The Company entered into a Securities Purchase Agreement (the "Purchase Agreement"), dated February 9, 2009, with Young Energy Prize S.A. ("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 $10,000,000. The 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. The Company received gross proceeds of $10 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 private placement 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. In the Purchase Agreement, YEP represented to the Company that: (a) it is an accredited investor, as such term is defined in Rule 501 of Regulation D promulgated under the Securities Act; (b) it acquired the Shares and the Warrant as principal for its own account for investment purposes only and not with a view to or for distributing or reselling the Shares and the Warrant or any part thereof, and (c) it is knowledgeable, sophisticated, and experienced in making, and qualified to make, decisions with respect to investments in securities representing an investment decision similar to that involved in the purchase of the Shares and the Warrant.

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 $4,276,472, were recorded in the consolidated statement of income.

Recent Accounting Pronouncements

On December 31, 2008, the Securities and Exchange Commission ("SEC") published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The SEC requires companies to comply with the amended disclosure requirements for annual reports for fiscal years ending on or after December 15, 2009. The SEC's new rules were effective for the Company for the fiscal year ended June 30, 2010.

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (ASU) 2010-03, *Extractive Activities Oil and Gas (Topic 932) — Oil and Gas Reserve Estimation and Disclosures,* and in April 2010 issued ASU 2010-14, *Accounting for extractive activities — Oil and Gas —Amendments to paragraph 932-10-599-1,* to align the oil and gas reserve estimation and disclosure requirements of FASB ASC Topic 932, *Extractive Activities — Oil and Gas,* with the requirements in the SEC's new oil and gas reporting requirements. The ASU was effective for the Company for the fiscal year ended June 30, 2010.

2. Restatement of Financial Information

Subsequent to the issuance of our 2010 annual report on Form 10-K, during the nine months ended March 31, 2011 we determined that our consolidated statement of cash flows for the year-ended June 30, 2010, reflected a foreign currency exchange loss in the line item "effect of exchange rate changes on cash and cash equivalents", rather than including it with the adjustments to reconcile net income (loss) to net cash provided by operating activities. Because this is a non-cash expense included in net income, it should have been added back to net income in order to properly reconcile net income to cash provided by operating activities within the statement of cash flows. The exclusion of this adjustment to reconcile net income resulted in understating the net cash provided by operating activities and overstating the effect of exchange rate changes on our cash and cash equivalents line items within the statement of cash flows.

This error also affected our consolidated statement of cash flows for the six month periods ended December 31, 2010 and 2009, the three month periods ended September 30, 2010 and 2009, as well as the fiscal year ended June 30, 2009. This error did not affect our Balance Sheet or Statements of Operations for any of the prior periods impacted, nor did it affect the total cash increase or decrease reported for any of the periods impacted.

Table of Contents

The statements of cash flows for the twelve months ended June 30, 2010 and June 30, 2009 as contained herein has been adjusted for the restatement discussed above. The following is a summary of the items reclassified on the originally issued Consolidated Statement of Cash Flows for the twelve months ended June 30, 2010 and June 30, 2009:

CONSOLIDATED STATEMENT OF CASH FLOWS

	June 30, 2010		
	As Previously Reported	Adjustments	As Restated
Adjustments to reconcile net loss to net cash provided by operating activities:			
Foreign currency exchange loss	$ —	$ 732,091	$ 732,091
Net cash provided by operating activities	$ 3,220,422	$ 732,091	$ 3,952,513
Effect of exchange rate changes on cash and cash equivalents	$ 2,613,893	$(732,091)	$ 1,881,802

	June 30, 2009		
	As Previously Reported	Adjustments	As Restated
Adjustments to reconcile net loss to net cash provided by operating activities:			
Foreign currency exchange loss	$ —	$ 951,458	$ 951,458
Net cash provided by operating activities	$ 9,239,052	$ 951,458	$10,190,510
Effect of exchange rate changes on cash and cash equivalents	$(6,162,679)	$(951,458)	$ (7,114,137)

3. Fair Value Measurements

The Company's items to which fair value measurements apply are securities available for sale. Securities available for sale are classified as Level 1 in the fair value hierarchy. These investments are traded in active markets and quoted prices are available for identical investments.

Cash balances were $14,037,404 as of June 30, 2011 and the remaining $6,379,221 was held in time deposit accounts in several Australian banks that have terms of 90 days or less, and are therefore classified as cash equivalents. The fair value of cash equivalents approximates carrying value due to the short term nature of those instruments. Commonwealth Bank holds 60% of the cash and cash equivalent balance.

The following table presents the amounts of assets carried at fair value at June 30, 2011 and 2010 by the level in which they are classified within the valuation hierarchy:

	Fair Value Measurements Using Quoted Prices at	
Description	6/30/11 in Active Markets for Identical Assets Level 1	6/30/10 in Active Markets for Identical Assets Level 1
Securities available for sale	$ 238,070	$ 192,417

Table of Contents

4. Property and equipment

Property and equipment consisted of the following as of June 30:

	2011	2010
Oil and gas properties		
Subject to depletion	$ 130,491,220	$109,989,733
Not subject to depletion (unproved)	8,085,402	4,305,336
Less assets held for sale	—	(648,217)
Total costs	138,576,622	113,646,852
Less accumulated depreciation, depletion	(114,907,383)	(94,516,696)
Net oil and gas properties	23,669,239	19,130,156
Land, buildings and equipment	4,088,759	3,328,670
Less accumulated depreciation	(2,859,137)	(2,196,040)
Net Land, buildings and equipment	1,229,622	1,132,630
Field equipment	6,390,383	5,843,939
Less accumulated depreciation	(2,135,061)	(192,742)
Net field equipment	4,255,322	5,651,197
Total property and equipment, net	**$ 29,154,183**	**$ 25,913,983**

MPC had the following amounts of depletion and depreciation costs related to oil & gas properties recorded in the consolidated statements of operations related to oil & gas properties for the years ended June 30:

	2011	2010	2009
Depletion and depreciation expense, Oil & Gas properties	$1,187,797	$4,507,582	$6,681,468
Depletion and depreciation expense, all other assets	1,139,020	172,658	104,484
Total Depletion, Depreciation and Amortization	$2,326,817	$4,680,240	$6,785,952

During the years ended June 30, 2011, 2010 and 2009, the depletion rate by field was as follows:

	2011	2010	2009
		Percent	
Mereenie and Palm Valley (Australia)	*	32.2	63.8
Nockatunga (Australia) — sold in 2010	—	—	64.6
Cooper Basin (Australia) — sold in 2010	—	—	13.3
Poplar Field	1.7	13.0	—

* Because we have no proved oil reserves for SEC reporting purposes and insignificant gas reserves in Australia, MPAL producing assets have been depleted down to salvage value.

Table of Contents

Exploratory and Dry Hole Costs

Exploration and dry hole costs are included in the consolidated statements of operations. Components of these costs are as follows:

Exploration and Dry Hole Costs	Years Ended June 30, 2011	2010	2009
MPAL — Australia	$ 975,898	$ 713,690	$3,154,679
MPAL — United Kingdom (1)	1,401,807	559,578	321,258
Popular Field (2)	476,127	—	—
Total	$2,853,832	$1,273,268	$3,475,937

(1) Includes a write off of expired permits of $66,000 and $295,000 for June 30, 2011 and June 30, 2009, respectively.
(2) Includes a write off to expense of previously capitalized amounts of $32,000 for June 30, 2011.

Impairment Losses

Impairment losses included in the Consolidated Statement of Operations for June 30, 2011 totaled $173,400. The Company recorded impairment losses on Oil and Gas properties during 2011 of approximately $173,000, of which $122,861 relates to ATP 674 and 733 which were held for sale at June 30, 2010 and related to the Cooper Basin Asset Sales (See Note 10). The remaining loss of $50,539 was related to the decreased value of U.K. exploration permits and licenses that were recognized under purchase accounting (PEDL #126).

The Company recorded impairment losses during 2010 of approximately $2 million, of which $1.6 million of this amount related to its Udacha assets, PEL91 and 106, located in the Cooper Basin. This loss reflected the difference in the fair value, which was based on the expected sales price, and the net book value of the assets at December 31, 2009, and is reported as an impairment loss in the statement of income. In addition, the Company wrote down the value of its Dingo assets (approximately $213,000) and has written off the value of U.K. permits that will not be renewed ($232,000).

An impairment loss of $63,740 was recorded in 2009 relating to the decreased value of U.K. exploration permits and licenses that were recognized under purchase accounting. The losses related to the exploration permits and licenses resulted from the ongoing exploration program which did not result in discovery of reserves.

These losses all related to the MPAL segment.

5. Asset Retirement Obligations

A reconciliation of the Company's asset retirement obligations for the years ended June 30, is as follows:

	2011	2010
Balance at beginning of year	$ 9,292,556	$ 9,815,262
Liabilities incurred — acquisition of Nautilus	—	1,649,000
Liabilities incurred — acquisition of working interest	50,414	667,218
Accretion expense	563,628	748,209
Revisions to estimate (1)	(128,805)	(2,231,849)
Sale of Cooper Basin assets	—	(1,864,783)
Exchange effect	1,619,617	509,499
Balance at end of year	$11,397,410	$ 9,292,556

(1) During the fiscal years ended June 30, 2011 and 2010, changes to estimated restoration dates and costs resulted in decreases in total asset retirement obligations.

6. Capital and Stock-Based Compensation

On December 8, 2010, shareholders approved an amendment to the Company's 1998 Stock Incentive Plan ("The Plan") to increase the authorized shares of common stock reserved for awards under the Plan by 2,000,000 shares, to a total of 7,205,000 shares. These authorized shares can take the form of non-qualified stock options, stock appreciation rights (SARs), restricted share awards, annual awards of stock to non-employee directors and performance based awards.

Options and non-vested shares

The Plan provides for non-qualified options to be issued with an exercise price of not less than fair value of the stock price on the date of the award and for a term of not greater than ten years. The option expense is recognized in the statement of operations in salaries and benefits using the accelerated method for the time-based awards with graded vesting and over the derived term for Performance based options (PBO's). The time-based stock options vest in equal annual installments over the vesting period, which is also the requisite service period. The Company determines the fair value of all time based options at the date of grant using the Black-Scholes option pricing model using the "simplified" life method to determine the expected term. The "simplified method" is appropriate for companies with insufficient historical exercise data to provide a reasonable basis upon which to estimate the expected term. Option valuation models require the input of certain assumptions including the expected stock price volatility. Stock price volatility is estimated based upon the Company's historic stock price volatility. Time based stock options are generally granted with a 3-year vesting period and a 10-year term. All options vest in full in the event of a change of control of the Company.

As of June 30, 2011, 1,270,000 options were available for future issuance under the Plan. The following is a summary of option transactions for the three years ended June 30, 2011:

Options Outstanding	Expiration Dates	Number of Shares	Exercise Prices ($) annual weighted avg. price	Weighted average Grant Date Fair Value
June 30, 2008		530,000	($1.51 weighted average price)	
Awarded	Dec. 2018	2,712,500	1.20	
June 30, 2009		3,242,500	($1.25 weighted average price)	$ 0.69
Awarded	July 2019	387,500	1.20	
Awarded	Oct. 2019	150,000	1.40	
Awarded	Dec. 2019	100,000	1.72	
June 30, 2010		3,880,000	($1.26 weighted average price)	$ 0.85
Awarded	Aug. 2020	400,000	1.84	
Awarded (1)	Aug. 2020	400,000	1.84	
Awarded	April 2020	700,000	2.24	
Awarded	April 2021	250,000	2.41	
Exercised		(30,000)	1.45	
Forfeited (1)		(400,000)	1.84	
June 30, 2011		5,200,000	($1.49 weighted average price)	$ 1.10

(1) These 400,000 options issued this fiscal year were forfeited as a result of the termination of the Evans Shoal agreement, see Note 12.

Table of Contents

The weighted average remaining contractual term as of June 30, 2011 is 7.64 years.

Summary of Options Outstanding at June 30, 2011

Year Awarded	Expiration fiscal year	Total Awarded	Total Vested and exercisable	Exercise Prices ($)
Fiscal year 2006	2015	400,000	400,000	1.60
Fiscal year 2008	2018	100,000	100,000	1.16
Fiscal year 2009	2019	2,712,500	2,100,000	1.20
Fiscal year 2010:	2020	387,500	300,000	1.20
	2020	150,000	75,000	1.40
	2020	100,000	50,000	1.72
Fiscal year 2011:	2020	700,000	233,332	2.24
	2021	400,000		1.84
	2021	250,000		2.41
Total fiscal year 2011		1,350,000		
		5,200,000	3,258,332	

The weighted average exercise price of the vested shares is $1.33.

Summary of Unvested Options at June 30, 2011

	Options	Weighted Avg. Grant Date Fair Value ($)
Unvested Options at June 30, 2010	1,650,000	0.76
Vested during current year	(1,058,332)	0.83
Granted during current fiscal year	1,750,000	1.10
Forfeited during current fiscal year	(400,000)	0.92
Unvested Options at June 30, 2011	1,941,668	0.90

Total non-cash compensation costs included in the consolidated statements of operations in salaries and benefits was $1,611,182, $1,805,056 and $83,560 for the years ended June 30, 2011, 2010, and 2009 respectively. Additional non-cash charges related to non-employee options of $58,878, $398,088 and $0.00 is included in the consolidated statements of operations in other administrative expenses for the years ended June 30, 2011, 2010, and 2009 respectively. As of June 30, 2011, 2010, and 2009 there was $1,084,997, $1,448,257 and $1,797,941 of unrecognized compensation cost related to stock options. The June 30, 2011 unrecognized compensation will vest over weighted average 1.09 years.

During the year ended June 30, 2011, 30,000 options were exercised by a former executive officer. The intrinsic value for those options was $43,200. No options were exercised in fiscal years 2010 and 2009.

During the year ended June 30, 2011, 400,000 options were forfeited. These options were issued to the Company CFO in August 2010. Non-cash stock compensation expense of $266,739 was recorded in the nine months ended March 31, 2011 relating to these options. The total expense was reversed at June 30, 2011. The PBO's were to vest in full upon the completion of the planned purchase by MPAL of an ownership interest in the Evans Shoal field, which did not occur (see Note 12).

During the current fiscal year ending June 30, 2012, an additional 1,274,998 of the above unvested options are expected to vest.

The aggregate intrinsic value of the 5,200,000 options outstanding was $3,405,840 at June 30, 2011. The aggregate intrinsic value of the 3,258,332 vested options outstanding at June 30, 2011 was $2,649,697.

Non-employee options

In fiscal year 2010, the Company granted 262,500 time-based options, with an exercise price of $1.20 per share to a non-employee consultant. There were no non-employee options awarded in fiscal year 2009 or 2011.

Since these options were issued to a non-employee, the Company determines their fair value at the end of each reporting period until the options vest. The option expense is recognized in the statement of operations under other administrative expenses using the accelerated method for the time-based awards with graded vesting and over the derived term for PBO's.

The fair value of these time-based options at June 30, 2011 was determined to be $313,011 based on the Black-Scholes valuation model using the following assumptions:

	June 30, 2011
Fair value measurement date	June 30, 2011
Number of shares	262,500
Risk free interest rate	2.69%
Expected life	7.58 yrs
Expected volatility (based on historical price)	61.38%
Exercise price	$ 1.20
Fair value at period end	$313,011
Vest beginning	February 2, 2010
Expire on	February 2, 2019

The expected life of these time based awards is the remaining contractual term.

Employee and director option and share based compensation

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, however, subject to a maximum annual cap of 15,000 shares. The Company issued 90,000 shares in January 2011, pursuant to this policy.

During the fiscal year ended June 30, 2011, 650,000 stock options were issued to employees as time-based options. Another 400,000 options were granted to an employee as performance based options, however these 400,000 shares were forfeited as part of the dissolution of the Evans Shoal Transaction (Note 12). Another 700,000 options were issued to the Company's directors during the current fiscal year.

The Company determines the fair value of the time based options at the date of grant using the Black-Scholes option pricing model using the "simplified" life method. Option valuation models require the input of certain assumptions including the expected stock price volatility. The assumptions used to value the Company's time based grants were as follows:

	Employee Time based	Employee Time based	Employee PBO (1)	Director Time based
Grant Date	4/25/2011	8/2/2010	8/2/2010	12/8/2010
Number of shares	250,000	400,000	400,000	700,000
Risk free interest rate	2.43%	2.23%	1.64%	2.07%
Expected life	6.00yrs	6.00yrs	5.00yrs	5.52yrs
Expected volatility (based on historical price)	58.18%	61.54%	56.00%	55.23%
Exercise price	$ 2.41	$ 1.84	$ 1.84	$ 2.24
Fair Value	$334,274	$432,399	$ N/A	$719,049
Vest beginning	April 25, 2012	August 2, 2011	N/A	April 1, 2011
Expire on	April 25, 2021	August 2, 2020	N/A	April 1, 2020

(1) these PBO's were forfeited during the year ended June 30, 2011.

The time based stock options vest in equal annual installments over the vesting period, which is also the requisite service period. Time based stock options are generally granted with a 3-year vesting period and a 10-year term. All options vest in the event of change of control of the Company.

On March 31, 2010, the Company also granted to its directors 350,000 non-vested shares of Company common stock which vest over 3 years. Of these shares, 141,666 vested on April 1, 2010, 104,167 vested on April 1, 2011 and 104,167 will vest on April 1, 2012.

7. Income Taxes

Components of (loss) income before income taxes by geographic area (in thousands) are as follows:

	Years Ended June 30,		
	2011	2010	2009
United States	$ (6,780)	$(8,456)	$(3,845)
Foreign	(20,517)	9,644	6,708
Total	$(27,297)	$ 1,188	$ 2,863

Table of Contents

Reconciliation of the provision for income taxes (in thousands) computed at the Australian statutory rate to the reported provision for income taxes is as follows:

	Years Ended June 30,		
	2011	2010	2009
Tax provision computed at statutory rate (30)%	$ (8,088)	$ 356	$ 859
MPC (parent company) nontaxable losses	—	—	1,154
Non-taxable Australian revenue	(822)	(953)	(342)
Change in valuation allowance	17,135	(346)	382
Rate differential on MPC book loss	(271)	(338)	(154)
MPC capitalized facilitation costs	106	201	268
MPC taxable dividend from MPAL, net of foreign tax credits	932	1,690	—
Nondeductible warrant and stock related compensation	—	2,203	—
MPC adjustment to foreign tax credit carryforward	(3,411)	—	—
Other	(440)	(167)	31
Consolidated income tax provision	$ 5,141	$2,646	$ 2,198
United Stated current tax (benefit) provision	$ (127)	$ 375	$ —
Foreign current tax (benefit) provision	(87)	1,349	3,816
Current income tax (benefit) provision	$ (214)	$1,724	$ 3,816
United States deferred income tax (benefit) provision	$ (195)	$ 195	$ —
Foreign deferred income tax provision (benefit)	5,550	727	(1,618)
Deferred income tax provision (benefit)	$ 5,355	$ 922	$(1,618)
Consolidated income tax provision	$ 5,141	$2,646	$ 2,198
Effective tax rate	(19)%	223%	77%

Significant components of the Company's deferred tax assets and liabilities (in thousands) were as follows:

	June 30, 2011	June 30, 2010
Deferred tax liabilities		
Stepped up basis of oil and gas properties	$ (690)	$ (1,046)
Other	(901)	(195)
Total deferred tax liabilities	$ (1,591)	$ (1,241)
Deferred tax assets		
Acquisition and development costs	3,234	3,045
Asset retirement obligations	2,993	2,127
Net operating losses, capital loss carryforwards and foreign tax credits	12,188	3,122
United Kingdom exploration costs and net operating losses	2,358	1,545
Stock option compensation	1,673	—
Interest	539	539
Other	947	280
Total deferred tax assets	23,932	10,658
Valuation allowance (1)	(22,341)	(5,206)
Net deferred tax assets	$ —	$ 4,211

(1) The Company records a valuation allowance for deferred tax assets when management believes it is more likely than not that such assets will not be recovered. The current year increase in the valuation allowance of

$17,135 is primarily due to a valuation allowance recorded against the Company's Australian deferred tax assets. In evaluating the ability to recover these deferred tax assets, we considered all available positive and negative evidence, giving greater weight to the recent current loss, the absence of taxable income in the carryback period and the uncertainty regarding our ability to project financial results in future periods. Additionally, consistent with prior periods, the valuation allowance related to the Company's U.S. and U.K. deferred tax assets increased due to the generation of U.S. net operating losses, U.S. foreign tax credits, tax benefits from U.K. exploration costs and U.K. net operating losses.

Tax years that remain subject to examination are 1999, 2000, 2002 and 2005 and forward for the United Sates. Tax years that remain subject to examination for Australia are 2007 and forward for returns excluding issues previously under audit and 1997 and forward for amendment on issues previously under audit.

United States

At June 30, 2011, the Company had a net operating loss and foreign tax credit carry forwards for federal and state income tax purposes, respectively, which are scheduled to expire periodically as follows (in thousands):

	Net Operating Losses			Foreign Tax Credit
	Paroo USA Federal	MPC Federal	MPC State	MPC Federal
Expires:				
2011	$ 1,764	$ —	$ —	$ —
2012	2,856	—	—	—
2013	230	—	—	—
2019	96	—	—	—
2020	—	—	—	2,847
2021	25	—	—	925
2022	74	—	—	—
2023	3	—	—	—
2024	2	—	—	—
2025	1	—	—	—
2031	—	3,414	—	—
2033	—	—	3,414	—
Total	$ 5,051	$3,414	$3,414	$ 3,772

For financial reporting purposes, a full valuation allowance has been recognized to offset the deferred tax assets related to the U.S. state tax loss carry forwards and foreign tax credit carry forwards as it is more likely than not that under current circumstances such assets will not be recovered.

Australia

The gross deferred tax asset at June 30, 2011, consists primarily of acquisition and development costs, asset retirement obligations, net operating and capital loss carryforward and other assets which will result in tax deductions when paid. Australian net operating and capital losses carryforward indefinitely.

For financial reporting purposes, a full valuation allowance has been recognized to offset the deferred tax assets related to the Australian deferred tax assets, as it is more likely than not that under current circumstances such assets will not be recovered.

There are no significant uncertain tax positions for fiscal 2011 and 2010.

The Company has not provided United States income taxes on unremitted foreign earnings as those earnings are considered indefinitely invested. Determination of the amount of unrecognized deferred tax liability related to investment in foreign subsidiaries is not practicable.

Table of Contents

8. Debt

The Company’s long-term debt consists of the following:

	June 30, 2011
Note payable to bank in monthly installments of varying amounts plus interest, at 6.25% through June 25, 2014	$1,422,438
Less current portion	$ 552,000
Long-term debt, excluding current portion	$ 870,438

The following is a summary of principal maturities of long-term debt:

Less than 1 year	$ 552,000
One to Three years	$ 870,438
Three to Five years	$ —
Total	$1,422,438
Short Term Borrowing	$ 500

The variable rate of the note is based upon the Wall Street Journal Prime Rate (the index). The index was 3.25% as of June 30, 2011 resulting in an interest rate of 6.25% per annum as of June 30, 2011. Under the note payable and line of credit, Nautilus is subject to both financial and non-financial covenants. The financial covenant includes maintaining a debt service coverage ratio, as defined, of 1.2 to 1.0, which is calculated based on Nautilus’ annual tax return. As of June 30, 2011, based upon its FY 2010 tax return, Nautilus was in compliance with the financial covenant.

The Company also has a demand note payable with the same bank, classified as short term debt, which consists of advances under a $1,000,000 working capital line of credit. The total amount due on the line at June 30, 2011 was $500. The line bears interest at a variable rate which was 6.50% as of June 30, 2011. A portion of this revolving line of credit, $25,000, secures a letter of credit that is in favor of the Bureau of Land Management and another $25,000 of this revolving line of credit will secure a business credit card used by Nautilus. As of June 30, 2011, $949,500 is available under this line of credit.

The note payable to bank, letter of credit and the demand note payable are collateralized by first mortgages and assignment of production for the East Poplar and Northwest Poplar Fields and are guaranteed by Magellan Petroleum Corporation up to $6,000,000, not to exceed the amount of principal owed.

The debt referred to above is the debt of Nautilus.

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

Table of Contents

9. Geographic Information

As of each of the stated dates, the Company's revenue and long-lived assets (in thousands) were geographically attributable as follows:

	2011	2010	2009
Revenue:			
Australia	$12,775	$25,908	$28,027
United States	5,383	2,594	—
Other Foreign Geographic areas	19	23	164
	$18,177	$28,525	$28,191
Long-lived assets:			
Australia	$ 7,134	$22,682	$20,317
United States	21,660	19,354	660
Other Foreign Geographic areas	5,260	1,638	1,477
	$34,054	$43,674	$22,454

Substantially all of MPAL's gas sales were to the Power and Water Corporation of the Northern Territory of Australia. Oil sales during fiscal 2011 were 66.6% to the Santos group of companies, 20.2% to the Beach Petroleum group of companies and 13.2% to Origin Energy Resources.

Presently, all of the oil production from the Poplar Oil Field is being trucked to a terminal in Reserve, MT by Plains Marketing L.P., the buyer.

10. Sale of Cooper Basin Assets and Assets Held for Sale

During the year ended June 30, 2010 the Company entered into agreements to sell all of its assets located in the Cooper Basin, Australia. These assets, which related to the MPAL reporting segment, were disposed of because they are non-core to our strategies. All of these properties were previously carried in property and equipment at $20,684,459, net of accumulated depletion of $17,094,936.

The Cooper Basin Assets included the Nockatunga, Kiana and Aldinga oil fields and certain exploration licenses. The Company recorded a gain of approximately $6.8 million ($4.8 million net of tax) for the year ended June 30, 2010, and is reported on the (gain) loss on sale of assets line item in the Consolidated Statement of Operations.

The sale of the remaining Cooper Basin Assets, which includes certain associated exploration licenses, was completed in the current year ended June 30, 2011. These assets and the related liabilities were included in assets held for sale and liabilities related to assets held for sale at June 30, 2010. The Company recorded a gain of $937,000 ($656,000 net of taxes) in the year ended June 30, 2011 related to the sale of these assets and is reported on the (gain) loss on sale of assets line item in the Consolidated Statement of Operations.

The Company also recorded an impairment loss in the year ended June 30, 2010 of approximately $2 million. Of this amount, $1.6 million related to its Udacha assets, PEL91 and 106, located in the Cooper Basin. In the year ended June 30, 2011, an additional impairment of $122,000 related to ATP 674 & 733 was recorded. These impairments reflected the difference in the fair value, which was based on the expected sales price, and the net book value of the assets as of the dates each sale finalized, and is reported as an impairment loss in the Consolidated Statement of Operations.

11. Financing Arrangements with Young Energy Prize S.A.: Purchase Agreement, Investment Agreement and Related Amendments

Purchase Agreement and Related Amendments

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 Private Investment in a Public Equity ("PIPE") with its largest stockholder, Young Energy Prize S.A. ("YEP"), 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 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 (US) $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. On February 11, 2011, the Company and YEP executed a First Amendment to Securities Purchase Agreement ("First Amendment"). The First Amendment provides for a final closing of the Investment Transaction on or before June 15, 2011 to the extent that; (i) the Evans Shoal Transaction does not close as contemplated by the Amended Asset Sales Deed; and (ii) the failure to close the Evans Shoal Transaction results in the failure of the Company to recover an additional (AUS) $10 million deposit made towards the purchase price set forth in the Asset Sales Deed (the "Deposit Back Stop"). On February 17, 2011, the Company and YEP executed a Second Amendment to Securities Purchase Agreement ("Second Amendment") to clarify that the Deposit Back Stop set forth in the First Amendment and states that the funding contemplated by the First Amendment would not be withheld to the extent that the Company fails to satisfy any condition precedent set forth in the Second Purchase Agreement if such non-satisfaction is reasonably attributable to the failure to close the Evans Shoal Transaction.

Since the Amended Asset Sales Agreement has been terminated, and MPAL has received back the additional $10 million deposit, the Investment Transaction has not closed. The Company and YEP are in the process of terminating the Securities Purchase Agreement as amended by the First and Second Amendments.

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 (AUS)$85.45 million, which shall include the proceeds of the (U.S.)$15.6 million provided by the Investment Transaction, and of which (AUS)$10 million will be paid to the Company in reimbursement of the additional (AUS) $10 million deposit made towards the purchase price set forth in the Amended Asset Sales Deed, plus 50% (up to a cap of (US) $3.5 million) of all out-of-pocket costs and expenses incurred by the Company, MPAL and YEP associated with the Evans Shoal Transaction. The Investment Agreement states that the funding of the (AUS) $85.45 million by YEP is contingent upon the requirements and conditions of the Evans Shoal Agreement being satisfied or waived.

The Investment Agreement also outlines: (i) the Acquisition and Reorganization Plan ("Plan") which structures the direct or indirect participation of the Company and YEP in Santos' 40% interest in the Evans Shoal natural gas field (NT/P48) to be acquired pursuant to the Evans Shoal Transaction ("Evans Shoal Interest"); (ii) the basis on which post-completion payments required to be made by MPAL to Santos under the Amended Asset Sales Deed will be funded by the Company and YEP; and (iii) the Company and YEP's obligations to implement and fund the development of the Evans Shoal Interest ("Project").

The Side Letter clarifies the Investment Agreement by providing that the Company and not YEP shall be responsible for the payment of all third party out-of-pocket transaction costs and expenses incurred by the

Company, YEP and MPAL with respect to the Evans Shoal Transaction (“Costs”) to the extent that the Evans Shoal Transaction does not close and the Investment Transaction closes. The Letter also clarifies that such Costs include those relating to the financing of Evans Shoal Transaction and the Investment Transaction.

Since the Amended Asset Sales Agreement has been terminated, the transactions contemplated by the Investment Agreement have not closed. The Company and YEP are in the process of terminating the Investment Agreement, as amended by the Side Letter.

In connection with the unwinding of the Evans Shoal Transaction, the Company and Santos executed agreements to transfer their interests in the Amadeus licenses with a resulting ownership interest by the Company of 100% of the Palm Valley and Dingo gas fields. (See Note 20).

12. Evans Shoal Agreement

MPAL entered into an agreement with Santos Offshore Pty Ltd (“Santos”) on March 25, 2010 (“Assets Sale Deed”), to purchase Santos’ 40% interest in the Evans Shoal natural gas field (NT/P48) (“Evans Shoal Transaction”). Under the Asset Sales Deed, the Company agreed to pay Santos a time-staged cash consideration equal to (AUS) $100 million for its 40% interest in the Evans Shoal field which included a (AUS) $15 million deposit. The Company also agreed to pay additional contingent payments to Santos of (AUS) $50 million upon a favorable partner vote on any final investment decision to develop the Evans Shoal field and a further (AUS) $50 million upon first stabilized gas production from the field. Closing and completion of the purchase was subject to regulatory and other approvals. The Australian Foreign Investment Review Board indicated it had ‘no objection’ to the acquisition of Santos’ interest by Magellan.

The Asset Sales Deed was amended by the January 31, 2011 Deed of Variation (“Amended Asset Sales Deed”) which extended the closing date of the Evans Shoal Transaction through to May 31, 2011 in exchange for (1) MPAL’s release to Santos of the initial A$15 million escrow deposit payment made towards the purchase price (“First Escrow Amount”) and (2) an additional A$10 million escrow account deposit towards the purchase price (“Second Escrow Amount”). While the Amended Asset Sales Deed provided that the payment of the Second Escrow Amount would be made in accordance with the terms of the Amended Asset Sales Deed which provided certain defined circumstances under which MPAL was entitled to reimbursement of the deposit, the Deed of Variation re-classified the First Escrow Amount as non-refundable.

On July 21, 2011, Santos and MPAL executed a Release Agreement to (1) terminate the Amended Asset Sales Deed and (2) resolve all outstanding issues relating to the Amended Asset Sales Deed. Under the Release Agreement, MPAL received back the Second Escrow Deposit, plus all interest accrued on that amount from the date of deposit to the date of release and the parties agreed to mutually release each other from all claims arising out of the amended Assets Sales Deed and the Evans Shoal Transaction. As a result, the First Escrow Amount was written off.

13. Acquisitions

On October 15, 2009, MPC completed the purchase of an 83.5% controlling interest in Nautilus. Nautilus, based in Denver, Colorado, owns and operates oil development assets in Roosevelt County, Montana known as the East Poplar Unit and the Northwest Poplar Field. The controlling interest in Nautilus was purchased from White Bear LLC and the ECP Fund, SICAV-FIS, entities affiliated with Nikolay Bogachev and Thomas Wilson, two directors of the Company.

MPC also completed a consolidation of interests in the fields by purchasing a 25.05% average working interest from Hunter Energy LLC and a 3.25% average working interest from Nautilus Technical Group LLC (“NTG”). Magellan, on a consolidated basis owned a 85.7% average working interest in the Poplar Field as of June 30, 2011.

A working interest in an oil and gas property is considered a business for reporting purposes. As such, the purchases were accounted for under the acquisition method of accounting. Therefore, the purchase price is allocated to the assets acquired and liabilities assumed based on their estimated fair values. The results of Nautilus' operations have been included in the consolidated financial statements since October 15, 2009.

Supplemental Pro Forma Results (Unaudited)

The following pro forma financial information represents the combined results for the Company including, Nautilus (purchased in 2009), the working interests in the Poplar Field (purchased in 2010), as if the acquisitions had all occurred on July 1, 2008 for the two years ended June 30, 2010 and 2009:

	Year ended June 30,	
	2010	2009
Total Revenue	$30,159,759	$32,194,261
Costs and expenses	27,485,527	30,832,963
Operating income	2,674,232	1,361,298
Other (expense) income — net	(1,263,309)	1,527,112
Income (loss) before taxes	1,410,923	2,888,410
Income tax (provision)	(2,645,763)	(2,198,422)
Net (Loss) income	(1,234,840)	689,988
Less net income (loss) attributable to non-controlling interests in subsidiaries	47,735	66,953
Net (Loss) income attributable to Magellan Petroleum Corporation	$ (1,187,105)	$ 756,941

14. Leases

At June 30, 2011, future minimum rental payments applicable to MPC's, MPAL's and Nautilus' non-cancelable office and vehicle operating leases were as follows:

Fiscal Year	Future Minimum Rental Payments
2012	$ 513,895
2013	$ 487,623
2014	$ 93,445
2015	$ 95,314
2016 through 2019	$ 196,385

Operating lease rental expenses for each of the years ended June 30, 2011, 2010 and 2009 were $526,548, $386,513 and $415,760, respectively.

15. Segment Information

The Company has three reportable segments, MPC, and it's wholly owned subsidiaries- MPAL and Nautilus. The Company's chief operating decision maker is William H. Hastings (President and Chief Executive Officer) who reviews the results of the MPC, MPAL, and Nautilus businesses on a regular basis. MPC, MPAL, and Nautilus all engage in business activities from which they may earn revenues and incur expenses. MPAL and its subsidiaries are considered one segment.

Table of Contents

	Years Ended June 30, 2011	2010	2009
Revenues:			
MPC	$ 2,723	$ 2,826	$ 164
Nautilus	3,804	2,291	—
MPAL	12,775	25,908	28,027
Inter-segment revenue elimination	(1,125)	(2,500)	—
Total consolidated revenues	$ 18,177	$ 28,525	$ 28,191
Investment and other income:			
MPC	$ 43	$ 1,395	$ 24
Nautilus	4	18	—
MPAL	910	1,600	1,559
Inter-segment investment income elimination	(34)	—	—
Total consolidated	$ 923	$ 3,013	$ 1,583
Net (loss) income attributable to MPC:			
MPC	$ (6,429)	$ (263)	$ (885)
Nautilus	(23)	(55)	—
MPAL	(25,969)	7,569	4,550
Inter-segment elimination	(12)	—	—
Inter-segment dividend elimination	—	(8,698)	(3,000)
Consolidated net (loss) income attributable to MPC	$(32,433)	$ (1,447)	$ 665
Assets:			
MPC	$ 83,324	$ 90,345	$ 68,349
Nautilus	16,985	5,427	—
MPAL	49,291	63,131	69,711
Inter-segment elimination	(6,631)	—	—
Inter-segment equity elimination	(71,394)	(68,197)	(66,356)
Total consolidated assets	$ 71,575	$ 90,706	$ 71,704
Expenditures for additions to long-lived assets:			
MPC	$ 794	$ 306	$ —
Nautilus	2,095	328	—
MPAL	1,679	1,642	2,430
Total expenditures for additions to long-lived assets	$ 4,568	$ 2,276	$ 2,430
Other significant items:			
Depletion, depreciation and amortization:			
MPC	$ 272	$ 77	$ 5
Nautilus	803	448	—
MPAL	1,252	4,155	6,781
Total consolidated	$ 2,327	$ 4,680	$ 6,786
Production costs:			
MPC	$ 750	$ 158	$ —
Nautilus	2,227	1,373	—
MPAL	6,270	8,585	8,153
Total consolidated	$ 9,247	$ 10,116	$ 8,153
Exploratory and dry hole costs:			
MPC	$ 325	$ —	$ —
Nautilus	151	—	—
MPAL	2,378	1,273	3,476
Total consolidated	$ 2,854	$ 1,273	$ 3,476
Income tax expense:			
MPC	$ (322)	$ 570	$ 41
Nautilus	—	—	—
MPAL	5,463	2,076	2,157
Total consolidated	$ 5,141	$ 2,646	$ 2,198

Table of Contents

16. Commitments and Contingencies

The Company is exposed to oil and gas market price volatility and for gas sales uses fixed pricing contracts with inflation clauses to mitigate this exposure.

The following is a summary of our consolidated commitments and contingencies at June 30, 2011, in thousands:

	TOTAL	LESS THAN 1 YEAR	1- 3 YEARS	3- 5 YEARS	MORE THAN 5 YEARS
Operating lease obligations	$ 1,387	$ 514	$ 581	$ 193	$ 99
Purchase obligations (1)	4,516	3,056	1,460	—	—
Asset retirement obligations (2)	11,397	—	280	—	11,117
Note payable without interest	1,422	552	870	—	—
Total	$18,722	$ 4,122	$ 3,191	$ 193	$ 11,216

(1) Represents firm commitments for exploration and capital expenditures related to MPAL. Firm Commitments decreased $2.7 million offset by a $1.4 million increase caused by a 24% increase in exchange rates over June 30, 2010. The decrease was due to the delay of portions of the U.K. work program. Although the Company is committed to these expenditures, some may be farmed out to third parties. Additional contingent expenditures of $30,463,000 which are not legally binding have been excluded from the table above and based on exploration decisions would be due as follows: $0 (less than 1 year), $3,621,000 (1-3 years), $26,842,000 (3-5 years), and $0 (greater than 5 years). This figure is a $2.7 million increase over prior years reporting excluding the exchange rate effect.

(2) See Note 5 for changes in Asset Retirement Obligations.

Gas Supply Contracts

In 1983, the Palm Valley Producers commenced the sale of gas to Alice Springs under a 1981 agreement. That agreement terminated in June 2008. In 1985, the Palm Valley Producers and Mereenie Producers signed agreements for the sale of gas to Power and Water Corporation ("PWC") through its wholly-owned company Gasgo Pty Ltd ("Gasgo"), for use in PWC's Darwin electricity generating station and at a number of other generating stations in the Northern Territory. The price of gas under the Palm Valley gas contract is adjusted quarterly to reflect changes in the Australian Consumer Price Index. The gas is delivered into the 922-mile Amadeus Basin gas pipeline which was built by an Australian consortium in 1987. Since 1985, there were several additional contracts for the sale of Mereenie gas, the latest being the Mereenie Sales Agreement No. 4 in June 2006 for the supply of an additional 4.4 Bcf of gas to be supplied prior to December 31, 2008. The principal Mereenie contracts and supply obligations under the various agreements expired in January and June 2009 and September 2010. The current Palm Valley gas contract expires in January 2012. Refer to Note 20, Santos Gas Contract.

MPAL's major customer, PWC, contracted with Eni Australia in 2006 for the supply of PWC's Northern Territory gas demand requirement for twenty-five years, commencing January 2009. Eni Australia expected to commence sales from its Blacktip field offshore of the Northern Territory in January 2009; however, the Blacktip development encountered significant delays and commenced partial production in September 2009 with full production not achieved until February 2010. The Mereenie Producers continued to supply PWC's gas requirements on a reasonable endeavors basis to supplement Blacktip gas sales until early February 2010. The last Mereenie gas supply contract terminated in September 2010.

As MPAL has not been able to sell its uncontracted gas reserves, its revenues have declined in 2011. Palm Valley gas sales were approximately $1.7 million (net of royalties) or 100% of total gas sales for the year ended June 30, 2011, $2.1 million (net of royalties) or 15% of total gas sales for the year ended June 30, 2010 and $2.2 million (net of royalties) or 15% of total gas sales for the year ended June 30, 2009 There were no gas sales from

Table of Contents

Mereenie for the year ended June 30, 2011, $11.6 million (net of royalties) or 85% of total sales for the year ended June 30, 2010, and $12.4 million (net of royalties) or 85% of total gas sales for the year ended June 30, 2009.

At June 30, 2011, MPAL's commitment to supply gas under the above agreement was as follows:

Period	Bcf
Less than one year	0.43
Total	0.43

17. Selected Quarterly Financial Data (Unaudited)

The following is a summary (in thousands, except for per share amounts) of the quarterly results of operations for the year ended June 30, 2011 and 2010:

	September 30, 2010 3 Months	December 31, 2010 3 Months	March 31, 2011 3 Months	June 30, 2011 3 Months	June 30, 2011 Total
2011					
Total revenues	$ 3,699	$ 4,461	$ 4,867	$ 5,150	$ 18,177
Costs and expenses	(7,658)	(8,158)	(4,947)	(25,633)	(46,396)
Investment and other income	247	221	191	264	923
Income tax (provision) benefit	301	1,379	(178)	(6,643)	(5,141)
Net (Loss) Income	(3,411)	(2,097)	(67)	(26,862)	(32,437)
Net (Loss) Income attributable to MPC	(3,376)	(2,099)	(84)	(26,874)	(32,433)
Per share (basic & diluted) attributable to MPC	$ (0.06)	$ (0.04)	$ —	$ (0.51)	$ (0.62)
Average number of shares outstanding	52,336	52,336	52,456	52,456	52,399

	September 30, 2009 3 Months	December 31, 2009 3 Months	March 31, 2010 3 Months	June 30, 2010 3 Months	June 30, 2010 Total
2010					
Total revenues	$ 8,879	$ 9,716	$ 5,137	$ 4,793	$ 28,525
Costs and expenses (includes warrant expense)	(10,974)	(8,835)	(2,820)	(7,721)	(30,350)
Investment and other income	1,497	1,038	327	151	3,013
Income tax (provision) benefit	(699)	(323)	(1,464)	(160)	(2,646)
Net (Loss) Income	(1,297)	1,596	1,180	(2,937)	(1,458)
Net (Loss) Income attributable to MPC	(1,297)	1,592	1,162	(2,904)	(1,447)
Per share (basic & diluted) attributable to MPC	$ (0.03)	$ 0.03	$ 0.02	$ (0.06)	$ (0.03)
Average number of shares outstanding	49,546	51,680	51,990	52,336	51,411

An increased loss in the fourth quarter of fiscal year ending June 30, 2011, is partially due to the Loss on Evans Shoal deposit of $15.9 million (see Note 12) and the valuation allowance taken against our deferred tax assets (see Note 7). During the quarter ended March 31, 2011 and as previously disclosed in our related Form 10-Q, the Company recorded a cumulative out-of-period adjustment in connection with the foreign currency translation of a foreign currency loan. The translation adjustment was included in determining net income in error, rather than being recorded through the balance sheet in the accumulated other comprehensive income account. The adjustment decreased foreign transaction losses and accumulated other comprehensive income by

$786,040. Had the amounts been reflected during the first and second quarters of this fiscal year, in the periods in which they arose, foreign transaction losses and accumulated other comprehensive income would have decreased by $536,209 for the three months ended September 30, 2010 and $186,004 for the three months ended December 31, 2010. The net loss per basic and diluted share attributable to Magellan Petroleum Corporation common shareholders would not have changed for the three months ended September 31, 2010 or the three months ended December 31, 2010, however it would have been lower by $0.01 for the six months ended December 31, 2010, had the amounts been reflected in the periods in which they arose. Based upon an evaluation of all relevant quantitative and qualitative factors, and after considering the provisions of APB Opinion No. 28, Interim Financial Reporting, paragraph 29, SAB No. 99, Materiality, and SAB 108, management believes this correcting adjustment was not material to the Company's full year results for fiscal year ended June 30, 2011 or the trend of earnings or loss.

18. Related Party and Other Transactions

Edward B. Whittemore, the Company's corporate Secretary through December 8, 2010, is also a partner in the law firm of Murtha Cullina LLP, which was paid fees of $242,755, $347,361 and $689,652 by the Company in fiscal years 2011, 2010 and 2009, respectively. At June 30, 2011, 2010 and 2009, the Company's payables included $10,852, $69,882, and $50,812, respectively, owed to Murtha Cullina LLP.

The Company leases its Denver office (the office of Nautilus) from an entity owned partially by Thomas Wilson, a director of and consultant to the Company. The lease runs through February 2012. The total rent that was paid to the related parties from July 1, 2010 through June 30, 2011 was $72,295. The total rent paid to the related parties from October 15, 2009 (the date of the Nautilus acquisition — Note 13) to June 30, 2010 was $51,683. Consulting services of $144,000 charged by Mr. Wilson are included in the statement of operations for the twelve months ended June 30, 2011.

In July 2009, Young Energy Prize, S.A. ("YEP"), a Luxembourg entity whose Chairman and CEO is Nikolay Bogachev, a director of the Company, purchased from the Company 8,698,652 shares of common stock, plus a warrant to purchase an additional 4,347,826 shares. On August 5, 2010, Magellan executed a Purchase Agreement, an Investor's Agreement and a Memorandum of Agreement to finalize the terms of its second PIPE with YEP. The purchase agreement was amended in February 2011. The placement 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. 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 to clarify responsibility for the payment of all third party out-of-pockets transaction costs and expenses incurred by the Company, YEP and MPAL with respect to the Evans Shoal Transaction. (see Note 11)

On October 15, 2009, MPC completed the purchase of an 83.5% controlling interest in Nautilus. Nautilus, based in Denver, Colorado, owns and operates oil development assets in Roosevelt County, Montana known as the East Poplar Unit and the Northwest Poplar Field. The controlling interest in Nautilus was purchased from White Bear LLC and YEP I, SICAV — FIS, entities affiliated with Nikolay Bogachev and Mr. Wilson, two directors of the Company.

As of June 30, 2011, Nautilus Technical Group has an interest in Nautilus. NTG is owned in part by Mr. Wilson, a director of the Company; Mr. Monty Hoffman, a consultant to Nautilus; and Mr. Wayne Kahmeyer, the controller of Nautilus. MPC completed a consolidation of interests in the Poplar fields by purchasing a 2.0% working interest from Nautilus Technical Group LLC for $380,000, in the current fiscal year.

Mr. J. Robinson West, a director of the Company provided consulting services through PFC Energy on various Australian projects. Mr. West is Chairman, Founder and CEO of PFC Energy and PFC Energy has been paid $394,000 in fiscal year 2011, of which $241,651 was expensed in the prior fiscal year. At June 30, 2011 the Company's payables included $48,926 owed to PFC Energy.

19. Supplementary Oil and Gas Disclosure (Unaudited)

The consolidated data presented herein include estimates which should not be construed as being exact and verifiable quantities. The reserves may or may not be recovered, and if recovered, the cash flows therefrom, and the costs related thereto, could be more or less than the amounts used in estimating future net cash flows. Moreover, estimates of proved reserves may increase or decrease as a result of future operations and economic conditions, and any production from these properties may commence earlier or later than anticipated.

In June 2010, the Company adopted revised oil and gas reserve estimation and disclosure rules. The primary impact of the new disclosure is to conform the definition of proved reserves to the definition now included in the SEC “Modernization of Oil and Gas Reporting Release”, which was released by the SEC in December of 2008. The new rules revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economical to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows.

As part of the new disclosure requirements, we are required to define our geographic areas about which we will be reporting detailed oil and gas data. The revised rules require disclosing certain information by geographic area that represents 15% or more of our total proved reserves. A geographical area as defined by the SEC represents either 1) by individual country 2) by groups of countries within a continent or 3) by continent as deemed meaningful for disclosures by the Company. We have determined that for meaningful disclosure, we will continue to disclose Australia as a geographic area even though it does not presently represent 15% of our fiscal 2011 reserves. Therefore the geographic areas will include the United States and Australia. All other areas not representing a significant geographic area are reported below as “All other foreign Geographic areas”.

Reserve Estimation

The Company has limited staff and is dependent upon consultants and partnering arrangements including those for reserve estimation and review.

United States — The Company’s subsidiary, Nautilus, employs an internal petroleum engineer who works closely with management to ensure the integrity, accuracy and timeliness of data furnished to the independent petroleum consultants for their reserves review process. For the years ended June 30, 2010 and 2011 the reserve reports were prepared by Mr. Naing Aye. Mr. Aye holds a Bachelor of Science, Petroleum Engineering Degree from the Colorado School of Mines. He has the responsibility for maintaining the reserve software program and prepares the in-house reserve estimates. He has worked over 7 years in the Petroleum Industry, including 5 years of reserve evaluation experience. Mr. Aye is a member of the Society of Petroleum Engineers. Mr. Aye met the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company then has consultants perform an audit and any differences are reviewed with our senior geologist. No differences were identified in the review of the reserves estimate as of June 30, 2011.

At June 30, 2011, Allen & Crouch Petroleum Engineers, an independent petroleum consultant, conducted an audit of our United States reserves. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. Richard L. Vine P.E. of Allen & Crouch is the technical person responsible for overseeing the audit of our U.S. oil reserves estimates. Mr. Vine has a BS in Petroleum Engineering from the University of Wyoming and 31 years experience in property evaluation, reservoir, production, operations and drilling engineering as well as experience in management of both major and independent oil companies. At June 30, 2011, these consultants audited 100% of our U.S. proved and probable reserves. A copy of the summary reserve report of this independent petroleum consultant is provided as Exhibit 99.1 to this Annual Report on Form 10-K. Allen & Crouch does not own an interest in any of Magellan’s oil and gas properties and is not employed by Magellan on a contingent basis.

Nautilus staff met with the independent engineers to discuss the assumptions and methods used in the reserve estimation process. We provide historical information to our consultants for our properties such as ownership interest; oil and gas production; well test data; commodity prices and operating and development costs.

Australia — Ryder Scott Company (Ryder Scott), an independent petroleum engineering firm, has prepared an estimate of the Company's Australian oil and gas reserves as of June 30, 2011. Larry Thomas Nelms, an employee of Ryder Scott, is the primary technical person responsible for the estimate of the reserves. Mr. Nelms meets the requirements with regard to professional qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Detailed information regarding Mr. Nelms professional qualifications are included at the end of the reserves report provided as Exhibit 99.2 to this Annual Report on Form 10-K. Ryder Scott does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

The Company's internal geosciences professional staff worked closely with Ryder Scott to ensure the integrity, accuracy and timeliness of the data used to calculate the proved oil and gas reserves. Mervyn Cowie, Operations Director of Magellan Petroleum Australia Limited is the technical person at the Company who is responsible for overseeing the preparation of our Australian oil and gas reserves estimates. Mr. Cowie graduated from the University of Queensland in 1969 with a Bachelor of Science majoring in Geology & Mineralogy and is a Fellow of the Australasian Institute of Mining & Metallurgy. He has over 35 years experience in petroleum and mineral exploration and production in Australia, Indonesia, China and the U.S. and has over 10 years experience in reserve estimation in Australia. Magellan staff met with Ryder Scott to discuss the assumptions and methods used in the proved reserve estimation process. Magellan provided historical information to Ryder Scott for the oil and gas properties such as ownership interest; oil and gas production; well test data; commodity prices and operating and development costs. The preparation of the Company's proved reserve estimates are completed in accordance with our internal control procedures, which include the verification of input data used by Ryder Scott, as well as management review and approval. At June 30, 2011, these consultants prepared the estimate for 100% of our Australian proved, probable and possible reserves. A copy of the summary reserve report of the independent petroleum consultant is provided as Exhibit 99.2 to this Annual Report on Form 10-K.

All other Foreign Geographic areas — include operations in the U.K. and our carried interest in gas fields in Canada. There were no proved reserves reported in either of these areas.

Technologies used to determine Proved Reserve Estimate

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, volumetric, production type curve matching and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The SEC defines proved reserves as those volumes of crude oil; condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating they are scheduled to be drilled within five years, unless specific circumstances, justify a longer time.

Production quantities shown in the table set forth below are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids. The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Changes in our proved reserves for the three years ended June 30, 2011 were as follows:

	Total		Australia		United States		All other Foreign Geographic areas	
	Oil (a)	Gas (a)	Oil	Gas (c)	Oil (b)	Gas	Oil	Gas
Proved Reserves:								
June 30, 2008	778	7.18	778	7.11	—	—	—	0.07
Extensions and discoveries	—	0.05	—	—	—	—	—	0.05
Revision of previous estimates (f)	371	1.38	371	1.38	—	—	—	—
Production	(153)	(5.23)	(153)	(5.16)	—	—	—	(0.07)
June 30, 2009	996	3.38	996	3.33	—	—	—	0.05
Extensions and discoveries (g)	6,963	—	—	—	6,963	—	—	—
Revision of previous estimates (f)	(768)	1.64	(694)	1.63	(74)	—	—	0.01
Purchase of minerals in place (d)	2,631	—	—	—	2,631	—	—	—
Sales of minerals in place (e)	(205)	—	(205)	—	—	—	—	—
Production	(139)	(3.49)	(97)	(3.43)	(42)	—	—	(0.06)
June 30, 2010	9,478	1.53	—	1.53	9,478	—	—	—
Extensions and discoveries	6	—	—	—	6	—	—	—
Revision of previous estimates (f)	(340)	(0.24)	64	(0.24)	(404)	—	—	—
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	178	—	—	—	178	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—
Production	(132)	(0.86)	(64)	(0.86)	(68)	—	—	—
June 30, 2011	**9,190**	**0.43**	**—**	**0.43**	**9,190**	**—**	**—**	**—**
Proved Developed Reserves:								
June 30, 2009	789	3.38	789	3.33	—	—	—	0.05
June 30, 2010	2,515	1.53	—	1.53	2,515	—	—	—
June 30, 2011	2,249	0.45	—	0.45	2,249	—	—	—
Proved Undeveloped Reserves:								
June 30, 2009	207	—	207	—	—	—	—	—
June 30, 2010	6,963	—	—	—	6,963	—	—	—
June 30, 2011	6,941	—	—	—	6,941	—	—	—

(a) Oil reserves stated in MBbls natural gas reserves stated in Bcf

(b) Proved U.S. oil reserves at June 30, 2011 and June 30, 2010 include 1,067 and 1,124 MBbls respectively attributable to a consolidated subsidiary in which there is a 16.5% non-controlling interest.

Table of Contents

(c) The amount of proved reserves applicable to the Australian Gas only reflects the amount of gas committed to specific contracts and is net of royalties.
(d) Purchases of minerals in place during 2010 relate to Poplar Field acquisitions.
(e) Sales of minerals in place during 2010 relate to the Cooper basin asset sales.
(f) Revisions of estimates for each period presented 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.
(g) We evaluated the assets acquired in October 2009 and through petro physical geophysical and petro graphic data identified certain locations as proved undeveloped reserves based on our current proved developed wells.

There were no changes to proved reserves relating to improved recovery for the years ended June 30, 2011, 2009, or 2008. No wells were completed during the twelve months ended June 30, 2011.

The volumes and standardized measure reported for our Australian reserves are just for the Palm Valley area. The proved reserves in our Mereenie area at June 30, 2009 have been produced or revised down to zero as there is not sufficient history to show that the reduced cost structure of converting to an oil only play is economic.

OIL AND GAS PRODUCTION:

	Total		Australia		United States	All other
					Total US	
	Oil	Gas	Oil (1)	Gas (2)	Oil (3)	Gas
2011	132	0.861	64	0.861	68	—
2010	139	3.486	97	3.430	42	0.056
2009	153	5.229	153	5.161	—	0.068

		2011	2010	2009
1)	Australia oil production by field (000 bbl)			
	Mereenie	64	68	90
	Nockatunga	—	28	61
	Cooper Basin	—	1	2
		64	97	153
2)	Australia gas production by field (bcf)	2011	2010	2009
	Palm Valley	0.861	1.166	1.165
	Mereenie	—	2.264	3.996
		0.861	3.430	5.161
3)	U.S. oil production by field	2011	2010	
	East Poplar	51	32	
	Northwest Poplar	17	10	
		68	42	

Note: Sales and cost per unit of production are included in tables set forth in Item 1 of this report.

[Table of Contents](#)

Costs of Oil and Gas Activities (In thousands):

Fiscal Year 2011:	Total	Australia	United States	All other
Acquisition of properties:				
Proved	380	—	380	—
Unproved	150	—	150	—
Exploration Costs	6,446	976	2,447	3,023
Development Costs	290	4	286	—

Fiscal Year 2010:	Total	Australia	United States	All other
Acquisition of properties:				
Proved	13,456	—	13,456	—
Unproved	—	—	—	—
Exploration Costs	1,841	714	—	1,127
Development Costs	1,742	1,428	314	—

Fiscal Year 2009:	Total	Australia	United States	All other
Acquisition of properties:				
Proved	—	—	—	—
Unproved	—	—	—	—
Exploration Costs	3,925	3,439	—	486
Development Costs	631	631	—	—

Exploration costs have been expensed except for capitalized costs relating to drilling. In the U.K. exploration costs of $1,621,000 and $486,000 have been capitalized for 2011 and 2009, respectively. In the U.S. explorations costs of $1,971,000 have been capitalized for 2011.

Development costs have been capitalized.

The carrying value of our consolidated oil and gas properties as of June 30, 2011, and 2010 are presented in Item 8, Note 4.

Discounted Future Net Cash Flows:

Prices applied to proved reserves to calculate the standardized measure for each of the three years presented is as follows:

	At June 30,		
	2011	2010	2009
Australian $:			
Gas Prices (per MCF)			
Palm Valley (1)	2.26	2.2542	2.2532
Mereenie (2)			
MSA4	N/A	N/A	6.663
Oil Prices (per BBL) (2)			
Mereenie	N/A	N/A	95.73
Cooper			
Aldinga	N/A	N/A	97.80
Kiana	N/A	N/A	87.66
Nockatunga	N/A	N/A	90.82
U.S. $:			
Oil Prices (per BBL) (3)			
Poplar field	79.93	66.24	N/A

(1) Contract price through term of contract.
(2) Average twelve month price on the first of the month, no proved reserves 2010 and 2011.
(3) Average twelve month price on the first of the month, no U.S. reserves 2009.

Table of Contents

The following is the standardized measure of discounted (at 10%) future net cash flows (in thousands) relating to proved oil and gas reserves during the three years ended June 30, 2011. These amounts were calculated based on SEC price parameters using the average prices during the 12-month period ended June 30, 2011, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon (gas) products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. These prices were not changed except where different prices were fixed and determinable from applicable contracts.

Australia (in thousands):	2011	2010	2009
Future cash inflows	$ 972	$ 3,031	$ 88,152
Future production costs	(700)	(1,870)	(46,440)
Future development costs	—	(1,780)	(16,532)
Future income tax expense	—	(297)	(2,493)
Future net cash flows	272	(916)	22,687
10% annual discount for estimating timing of cash flows	(8)	1,062	(2,632)
Standardized measures of discounted future net cash flows	$ 264	$ 146	$ 20,055

United States (in thousands):	2011	2010	2009
Future cash inflows	$ 734,592	$ 627,842	$ —
Future production costs	(303,005)	(251,335)	—
Future development costs	(28,849)	(27,293)	—
Future income tax expense	(155,701)	(132,843)	—
Future net cash flows	247,037	216,371	—
10% annual discount for estimating timing of cash flows	(137,021)	(131,163)	—
Standardized measures of discounted future net cash flows	$ 110,016	$ 85,208	$ —

All other Geographic Areas (in thousands):	2011	2010	2009
Future cash inflows	$ —	$ —	$ 80
Future production costs	—	—	(70)
Future income tax expense	—	—	(3)
Future net cash flows	—	—	7
10% annual discount for estimating timing of cash flows	—	—	1
Standardized measures of discounted future net cash flows	$ —	$ —	$ 8

Total (in thousands):	2011	2010	2009
Future cash inflows	$ 735,564	$ 630,873	$ 88,232
Future production costs	(303,705)	(253,205)	(46,510)
Future development costs	(28,849)	(29,073)	(16,532)
Future income tax expense	(155,701)	(133,140)	(2,496)
Future net cash flows	247,309	215,455	22,694
10% annual discount for estimating timing of cash flows	(137,029)	(130,101)	(2,631)
Standardized measures of discounted future net cash flows	$ 110,280	$ 85,354	$ 20,063

The following are the principal sources of changes in the above standardized measure of discounted future net cash flows for the Australia (in thousands):

	2011	2010	2009
Net change in prices and production costs	$ 38	$ —	$(13,429)
Extensions and discoveries	—	—	—
Acquisitions of reserves	—	—	—
Revisions of previous quantity estimates	1,094	1,850	1,045
Changes in estimated future development costs	536	—	10,997
Divestiture of reserves	—	(11,687)	—
Sales and transfers of oil and gas produced	(1,940)	(12,299)	(18,169)
Previously estimated development cost incurred during the period	—	—	(1,124)
Accretion of discount	41	—	621
Net change in income taxes	297	2,227	4,463
Net changes in timing and other	52	—	(3,903)
	$ 118	$(19,909)	$(19,499)

The following are the principal sources of changes in the above standardized measure of discounted future net cash flows for the U.S. for 2011 and 2010. There were no United States reserves in 2009 (in thousands):

	2011	2010
Net change in prices and production costs	$ 24,899	$ —
Extensions and discoveries	117	115,092
Acquisitions of reserves	3,486	29,656
Revision of previous quantity estimates	(7,041)	(8,258)
Changes in estimated future development costs	(798)	—
Divestiture of reserves	—	—
Sales and transfers of oil and gas produced	(2,406)	(1,064)
Accretion of discount	13,893	1,725
Net change in income taxes	(16,125)	(53,722)
Net changes in timing and other	8,783	1,779
	$ 24,808	$ 85,208

The following are the principal sources of changes in the above standardized measure of discounted future net cash flows in aggregate for the Company for 2011 and 2010:

	2011	2010	2009
Net change in prices and production costs	$ 24,937	$ —	$(13,429)
Extensions and discoveries	117	115,092	—
Acquisition of reserves	3,486	29,656	—
Revision of previous quantity estimates	(5,947)	(6,408)	1,045
Changes in estimated future development costs	(262)	—	10,997
Divestitures of reserves	—	(11,687)	—
Sales and transfers of oil and gas produced	(4,346)	(13,363)	(18,169)
Previously estimated development cost incurred during the period	—	—	(1,124)
Accretion of discount	13,934	1,725	621
Net change in income taxes	(15,828)	(51,495)	4,463
Changes in timing and other	8,835	1,779	(3,903)
	$ 24,926	$ 65,299	$(19,499)

Table of Contents

Results of Operations

The following are the principal sources of changes in the above standardized measure of discounted future net cash flows in total for 2011, 2010 and 2009 (in thousands):

	Total			United States			Australia			Other Foreign Countries		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
Revenues:												
Oil sales	$ 11,815	9,887	11,480	$5,383	2,594	—	$ 6,432	7,292	11,480	$ —	—	—
Gas sales	1,797	13,615	14,740	—	—	—	1,778	13,593	14,576	19	23	164
Other production income	4,565	3,984	1,971	—	—	—	4,565	3,984	1,971	—	—	—
Total revenues	$ 18,177	27,486	28,191	$5,383	2,594	—	$12,775	24,869	28,027	$ 19	23	164
Costs:												
Production costs	9,247	10,116	8,153	2,977	1,530	—	6,270	8,586	8,153	—	—	—
Depletion, exploratory and dry hole costs	5,181	5,953	10,476	1,550	525	—	2,229	4,868	8,773	1,402	560	1,703
Total costs	14,428	16,069	18,629	4,527	2,055	—	8,499	13,454	16,926	1,402	560	1,703
Income before taxes	3,749	11,417	9,562	856	539	—	4,276	11,415	11,101	(1,383)	(537)	(1,539)
Income taxes	(1,625)	(3,640)	(2,860)	(342)	(216)	—	(1,283)	(3,425)	(2,860)	—	—	—
Net income from operations	$ 2,124	7,776	6,702	$ 514	323	—	$ 2,993	7,990	8,241	$(1,383)	(537)	(1,539)
Depletion per unit of production	A$ 15.42	6.82	8.39				15.42	6.82	8.39			
	U$ 2.19	6.50		2.19	6.50	—				—	—	—

* Income tax provision used for Australia is based on a rate of 30%. The United States 40% is due to a 25% Canadian withholding tax on Kotaneelee gas sales.

20. Subsequent Events

The Company has evaluated subsequent events and noted no additional events that require recognition or disclosure other than those listed below.

Evans Shoal Deposit

On July 21, 2011, Santos and MPAL executed a Release Agreement to (i) terminate the March 25, 2011 Assets Sale Deed (as amended by the January 31, 2011 Deed of Variation) ("ASD") which the terms of the Evans Shoal Transaction (See Note 12); and (ii) resolve all outstanding issues relating to the ASD. Under the Release Agreement, MPAL receives back the A$10 million escrow deposit made towards the purchase price stipulated in the ASD, plus all interest accrued on that amount from the date of deposit to the date of release. In addition, the parties have agreed to mutually release each other from all claims arising out of the ASD and the Evans Shoal Transaction. On July 22, 2011, the A$10 million deposit was refunded to MPAL.

Sale Agreement between Magellan Petroleum (N.T) Pty Ltd and Santos QNT Pty Ltd and Santos Limited

On September 14, 2011, Magellan Petroleum (N.T.) Pty Ltd ("Magellan NT"), a wholly owned subsidiary of MPAL, entered into a Sale Agreement ("Santos SA"), dated September 14, 2011 with the Santos QNT Pty Ltd ("Santos QNT") and Santos Limited ("Santos Entities") (such transaction referred to herein as the "Santos Transaction"). The Sale Agreement is subject to satisfaction of certain conditions by June 22, 2012. These conditions include approval of the Santos SA (and related transfers and dealings) under relevant petroleum legislation; Foreign Investment Review Board approval (which has now been obtained); execution of the GSPA (defined below); and certain third party approvals of the assignment of property interests, joint venture contracts and royalty obligations ("Conditions").

The Santos SA provides for the transfer of the following assets with effect as of July 1, 2011, subject to the satisfaction of the conditions:

- Magellan NT's 35% interest in each of the Mereenie Operating Joint Venture (Petroleum Leases 4 and 5 ("Mereenie Titles") and associated property interests, related joint venture contracts (including a crude oil sales contract) and plant and equipment, subject to royalty obligations) and the Mereenie Pipeline Joint Venture (Pipeline License 2 and associated property interests, related joint venture contracts and plant and equipment) (collectively, "Mereenie Interests")) to Santos QNT, giving the Santos Entities a combined 100% interest in the assets of each of the Mereenie Operating Joint Venture and the Mereenie Pipeline Joint Venture;
- The Santos Entities combined interests of 47.977% in the Palm Valley Joint Venture (Petroleum Lease 3 and associated property interests, related joint venture contracts (including a Gas Sales Agreement) and plant and equipment, subject to royalty obligations) (collectively "Palm Valley Interests") and combined interests of 65.6635% in the Dingo Joint Venture (Retention License 2, associated joint venture contracts and plant and equipment, subject to royalty obligations) (collectively, "Dingo Interests") to Magellan NT, giving Magellan NT a 100% interest in the assets of each of the Palm Valley Joint Venture and the Dingo Joint Venture.

The cash consideration payable for the sale of the Mereenie Interests by Magellan NT is A$28.0 million (plus or minus adjustments for the period from the Effective Date (July 1, 2011) to Completion, five business days after the Conditions have been satisfied (or as otherwise agreed between the parties), plus a Bonus Amount. During the period from Completion until 20 years after the Effective Date, the Santos Entities will pay Magellan NT a Bonus Amount based on volumes of net sales of petroleum from the Mereenie Interests meeting certain thresholds ("Threshold Level") set out in the Santos SA. If daily net sales average over a period of not less than 90 consecutive days within a specified rate band, then the specified Bonus Amount for that rate band shall be paid. If all rate bands are achieved the cumulative Bonus Amount shall be A$17.5 million. The Bonus Amount is only payable once in respect of each Threshold Level. Accordingly, once a Threshold Level has been achieved and a Bonus Amount paid, no further payment will be triggered for that Threshold Level.

The cash consideration payable for the sale of the Palm Valley Interests by the Santos Entities is A$2.9 million (plus or minus adjustments for the period from the Effective Date to Completion). The cash consideration payable for the sale of the Dingo Interests by the Santos Entities is A$0.1 million (plus or minus adjustments for the period from the Effective Date to Completion).

Due to the recent closing of this transaction, our consideration of the accounting implications of this transaction is not complete as of this filing, and for this reason we are not in a position to provide an estimate of the financial effect of the acquisition on the Company.

Gas Supply and Purchase Agreement between Magellan Petroleum (N.T) Pty Ltd and Santos QNT Pty Ltd

On September 14, 2011, Magellan NT entered into a Gas Supply and Purchase Agreement (the "GSPA"), dated September 14, 2011, with the Santos Entities (such transaction referred to herein as the "Santos Gas Contract").

The Santos Gas Contract is subject to Completion occurring under the Santos SA and provides for the sale by Magellan NT to the Santos Entities of a total contract gas quantity of 25.65PJ over the anticipated 17 year term of the GSPA, subject to certain limitations regarding deliverability into the Amadeus Pipeline.

The term of the GSPA shall commence on the later of Completion under the Santos SA, the first delivery of gas under a Concession GSPA or January 16, 2012 (when the existing gas sales agreement for the Palm Valley Gas Field expires) and will expire if the total contract quantity is reached before the expiry of 17 years. Under the

GSPA, the Santos Entities are required to use reasonable endeavors to enter into one or more agreements with their customers for the sale of gas solely from the Mereenie Gas Field, the Palm Valley Gas Field or other permissible fields under the GSPA and that collectively will require an average aggregate daily contract quantity for each day during the term of the GSPA of not less than 5.86 TJ (“Concession GSPA”).

The price for gas supplied by Magellan NT shall be the weighted average of the price obtained for all gas sold or to be sold by the Santos Entities from the Mereenie Interests during the relevant contract year.

The GSPA provides a detailed procedure to be followed by the parties in determining the amount of gas that will provided daily during each contract year. The maximum daily contract quantities under the GSPA (“Maximum DQ”) are based on a maximum annual contract quantity of 1.71PJ, spread evenly over a year. In the last two (2) years of the term (known as the “Recovery Period”), the maximum annual contract quantity will be one half of the difference between the total contract quantity of 25.65PJ and what has been sold to the Santos Entities by Magellan NT up to that date. On any day, Magellan NT is obliged (subject to the usual exceptions for planned and unplanned maintenance and force majeure) to supply the lesser of the Maximum DQ, the daily contract forecast quantities provided by Magellan NT prior to the commencement of a contract year and 80% of the quantities nominated by the Santos Entities’ customers under the Concession GSPAs (“Supply Obligation”).

If the term of the GSPA does not commence by April 15, 2012 (90 days after the expiry of the existing gas sales agreement for the Palm Valley Gas Field):

(i) The Santos Entities will purchase 460,000 GJ of gas in 2012 for a total price of A$2.0 million;

(ii) Under the Santos SA, the Bonus Amount associated with lowest Threshold Level will decrease from A$5,000,000 to A$2,000,000 and the Bonus Amount associated with the second highest Threshold Level will be increased from A$250,000 to A$1,250,000;

If a Concession GSPA is then entered part-way through 2012, the volume purchased (and the total price) will be decreased proportionately.

Due to the recent closing of this transaction, our consideration of the accounting implications of this transaction is not complete as of this filing, and for this reason we are not in a position to provide an estimate of the financial effect of the acquisition on the Company.

Lease Purchase and Sale and Participation Agreement with VAALCO energy (USA), INC.

On September 6, 2011, the Company and Nautilus entered into a Lease Purchase and Sale and Participation Agreement (the “VAALCO PSA”) with VAALCO energy (USA), INC (“VAALCO”) and simultaneously closed the transaction described therein (the “Closing Date”).

Pursuant to the VAALCO PSA, the Company received $5 million in cash on the Closing Date. VAALCO also agreed to drill three (3) new wells, at its sole expense as operator, to the Bakken formation and to formations below the Bakken (the “Deep Intervals”) in the Poplar Field. Upon completion of the three (3) new wells (“Obligation Wells”) in the Deep Intervals of the Poplar Field, VAALCO will earn a 65% working interest in the Deep Intervals within the Poplar Field. One well will is required to be spud on or before June 1, 2012 and the second and third are required to be spud on or before December 31, 2012. One well will be drilled horizontally to test the Bakken Formation, one well will be drilled vertically to test the Red River Formation, and a third will be targeted at VAALCO’s discretion. All production from an Obligation Well that is completed and the revenue from the sale thereof attributable to applicable leases shall be owned by Magellan/Nautilus and VAALCO consistent with their working interests of 35% and 65%, respectively, subject to all applicable burdens and taxes.

Under the VAALCO PSA, if VAALCO fails to drill and, if applicable, complete, any of the Obligation Wells in accordance with the agreement: (i) VAALCO will not be entitled to the assignment of the Deep Intervals; (ii) VAALCO shall have no further right to earn any interest in the Deep Intervals; (iii) the Company shall be entitled to retain the purchase price; (iv) VAALCO shall relinquish, effective as of the date of the failure, all of VAALCO's rights, title, and interest in any Obligation Well that has been drilled and, if applicable, completed; and the Company and Nautilus shall have the right to terminate the VAALCO PSA. However, VAALCO shall be entitled to retain any production and the sale proceeds there from attributable to a relinquished Obligation Well that has accrued to VAALCO's credit prior to the effective date of the relinquishment.

The VAALCO PSA also provides a process for the resolution of title defects identified through December 31, 2011.

We are unable to estimate the financial effect this transaction will have on the Company, as the results of the planned drilling program will dictate such financial results.

Purchase of the Non-Controlling Interest in Nautilus Poplar LLC.

On September 2, 2011, the Company entered into a Purchase and Sale Agreement with the members of Nautilus Technical Group LLC and Eastern Rider LLC (the members of NTG and ER individually a "Nautilus Seller" and collectively, the "Nautilus Sellers"), to acquire all of the membership interests in Nautilus Tech and ER, each a Colorado limited liability company ("Nautilus PSA"). As a result of the transaction, the Company acquired an additional 14.3% interest in the Poplar Field and now owns directly or indirectly through Nautilus, a 100% working interest in the Poplar Field, aside from certain working interest owners in the Northwest Poplar Field.

Prior to entering into the Nautilus PSA, the Company owned an 83.5% ownership interest in Nautilus, alongside Nautilus Tech and ER, which owned 10% and 6.5% membership interests, respectively. Nautilus Tech also owned a direct 2.9% working interest in the Poplar Field, aside from certain working interest owners in the Northwest Poplar Field alongside the Company's direct 28.3% working interest in the Poplar Field. Nautilus holds a 68.75% undivided working interest in the East Poplar Unit and varied majority interests in the Northwest Poplar Field, which were first discovered in the early 1950s and have unrecovered oil reserves. As a result of the acquisition of the Nautilus Sellers' interests in Nautilus Tech and ER ("Nautilus Transaction"), the Company is now Nautilus' sole member and interest holder of Nautilus and owns a 100% working interest in the Poplar Field, aside from certain working interest owners in the Northwest Poplar Field. The Nautilus Sellers include Mr. J. Thomas Wilson, a Company director, a consultant to Nautilus (each a "Related Seller") as well as certain other persons.

The Company paid $4 million in cash to the Sellers at closing and will issue approximately $2.0 million worth of new shares of the Company's common stock to acquire the Seller's estimated combined direct and indirect 14.3% interest in the Poplar Field. The cash consideration was paid to the Nautilus Sellers upon the execution of the Nautilus PSA. The $2 million worth of new shares of the Company's common stock, par value $.01 per share ("Common Stock"), less certain debt owed to the Company by Nautilus, Nautilus Tech and ER and certain costs equaling approximately $.3 million, will be issued on the earlier of (i) the business day that is three business days following the date on which the Company's Form 10-K for the year ending June 30, 2011 is filed with the Securities and Exchange Commission ("SEC") and (ii) September 30, 2011 ("Issuance Date"). Pricing of the shares will be determined according to the following guidelines; on the Issuance Date, the Company shall deliver to a Nautilus Seller shares of Common Stock as is determined by dividing the total share consideration allocated to the Nautilus Seller under the Nautilus PSA by, in the case of Related Seller, the greater of (i) the NASDAQ consolidated closing bid price of a share of Common Stock on the business day immediately preceding the execution of the PSA date and (ii) the NASDAQ official closing price of a share of Common Stock on the earlier of the business day that is two business days following the date on which MPET's Form 10-K for the year ending June 30, 2011 is filed with the SEC and September 22, 2011 ("NASDAQ Closing Price"). In the case of a Nautilus Seller that is not a Related Seller, MPET shall deliver shares of Common Stock as is determined by dividing the Total Share Consideration allocated to that Nautilus Seller by the NASDAQ Closing Price. All shares of Common Stock sold pursuant to the Nautilus Transaction will be registered in the name of the Nautilus Sellers and have not been registered under the Securities Act of 1933, as amended (the "Securities Act").

Due to the conflicting interests of Mr. Wilson resulting from his position with and financial interest in the Nautilus Sellers, the Board appointed a Special Transaction Committee ("Committee") to provide an independent forum for the consideration of the transactions contemplated by the Nautilus PSA and the related RRA (discussed below). At the August 24, 2011 Committee meeting, the Committee approved, and recommended that the Board approve, the transactions. On August 26, 2011, the Board approved the transactions.

Due to the recent closing of this transaction, our consideration of the accounting implications of this transaction is not complete as of this filing, and for this reason we are not in a position to provide an estimate of the financial effect of the acquisition on the Company.

Registration Rights Agreement between the Company and Owners of Nautilus Technical Group LLC and Eastern Rider LLC

On September 2, 2011, 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 owned by each Nautilus Seller and issued under the Nautilus PSA and, any securities issued or distributed in connection with such shares by way of stock dividend or stock split or other distribution or in connection with a combination of shares, recapitalization, reorganization, merger, consolidation, reclassification or otherwise and any other securities into which or for which shares of any other successor securities are received in respect of any of the foregoing ("Registrable Securities").

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 also agreed to indemnify each Nautilus Seller whose Registrable Securities are covered by a Registration Statement or Prospectus (each as defined in the RRA), each Nautilus Seller's officers, directors, general partners, managing members and managers, each person who controls (within the meaning of the Securities Act)) the Nautilus Seller and the officers, directors, general partners, managing members and managers of each such controlling person from and against any losses, claims, damages, or liabilities, expenses, judgments, fines, penalties, charges and amounts paid in settlement, as incurred, arising out of or based on certain untrue statements of material fact or certain omissions of material facts in any applicable Registration Statement and/or certain related documents.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Magellan Petroleum Corporation
Portland, Maine

We have audited Magellan Petroleum Corporation and subsidiaries' (the "Company's") internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on that risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment: (1) the inadequate design of internal controls related to the preparation and review of the Consolidated Statement of Cash Flows and (2) the ineffective operation of internal controls to evaluate the work of management's third party accounting experts, which are utilized to supplement management's internal review procedures for certain significant, complex, and/or non-routine matters. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended June 30, 2011, of the Company and this report does not affect our report on such financial statements.

In our opinion, because of the effect of the material weaknesses identified above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of June 30, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended June 30, 2011, of the Company and our report dated September 20, 2011 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of the Accounting Standards Update No. 2010-3, "Oil and Gas Reserve Estimation and Disclosures".

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

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Company's management, including William H. Hastings, the Company's President and Chief Executive Officer ("CEO"), and Antoine J. Lafargue, the Company's Chief Financial Officer ("CFO"), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Securities and Exchange Act of 1934, the "Exchange Act") as of June 30, 2011. Based on this evaluation, the Company's CEO and CFO concluded that the Company's disclosure controls and procedures were not effective because of the material weaknesses described below. However, the Company believes that the consolidated financial statements included in this Form 10-K fairly present, in all material respects, the Company's financial position, results of operations and cash flows for the periods presented and the Company is addressing the internal control issues by developing a thorough remediation plan in conjunction with its Audit Committee and third party accounting advisors, as further detailed below.

Management's Report on Internal Control Over Financial Reporting

Internal control over financial reporting (as defined in Rule 13a-15(f) adopted under the Exchange Act) is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the Company's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that the Company's receipts and expenditures are being made only in accordance with authorizations of the Company's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements. Management acknowledges its responsibility for establishing and maintaining adequate internal control over financial reporting. We have used the criteria established in Internal Control; Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in conducting our evaluation of the effectiveness of the internal control over financial reporting. Based on our evaluation, we concluded that the Company's internal control over financial reporting was not effective as of June 30, 2011 because of the material weaknesses in our internal controls over financial reporting as described below.

Deloitte & Touche LLP, our independent registered public accounting firm, has audited the financial statements included in this report on Form 10-K and has issued a report on our internal control over financial reporting. Their report is included in Item 8 of this report.

In light of the material weaknesses described below, we performed additional analysis to ensure our consolidated financial statements included herein, were prepared in accordance with generally accepted accounting principles and accurately reflect our financial condition, results of operations and cash flows for the fiscal year ended June 30, 2011 and other periods presented in this report. As a result, notwithstanding the material weaknesses discussed herein, management has concluded that the consolidated financial statements included in this Form 10-K fairly present, in all material respects, the Company's financial position, results of operations and cash flows for the periods presented.

Material Weakness in Internal Control Over Financial Reporting

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act), such that there is a reasonable possibility that a material misstatement of the Company's annual or unaudited condensed consolidated interim consolidated financial statements will not be prevented or detected on a timely basis.

1) Over the last year, the Company has significantly expanded the size and capability of its accounting staff to ensure that there are adequate financial reporting resources to manage and support the growth and increase in complexity of the Company's operations that occurred in the year ended June 30, 2011, as well as to ensure compliance with all applicable regulatory requirements. As a result of our improved review process and in combination with the evaluation and redesign of our internal controls over financial reporting, during our assessment of the Company's disclosure controls and procedures as of March 31, 2011, the Company identified an error in our unaudited condensed consolidated statement of cash flows. Certain foreign currency exchange losses were improperly excluded from the reconciliation of our net loss to cash flows from operations in our consolidated statement of cash flows. Please see Note 2 to our consolidated financial statements of this report dated June 30, 2011 for further information. In addition, despite improvements to our process, we found that certain other errors were made in the preparation of the Consolidated Statement of Cash Flows for the period ended June 30, 2011. The current period errors if taken on their own, would not be considered material, however in light of the previous material weakness, management has concluded that the aforementioned weakness has not been fully remediated as of June 30, 2011. These errors did not affect our Consolidated Balance Sheet or Consolidated Statements of Operations for any of the prior periods impacted, nor did it affect the total cash increase or decrease reported for any of the periods presented. Although the error did not have an impact on the aforementioned items, management has concluded that under Rule 13a-15(f) of the Exchange Act, the error described above is considered a material weakness in our internal controls over financial reporting. The error resulted from inadequate design of our internal controls related to the preparation and review of the Consolidated Statement of Cash Flows. The Company's process for preparing the Consolidated Statement of Cash Flows lacked sufficient procedures to review the Consolidated Statement of Cash Flows to ensure that all required adjustments necessary for proper presentation of the Consolidated Statement of Cash Flows were reflected therein.

2) Given the significant structural changes and transactions the Company has engaged in over the past two years, and despite expanded internal staff and resources, the Company decided to utilize third party accounting experts, to supplement management's internal review procedures for certain significant complex and/or non-routine matters. However, the Company's internal procedures require that the Company conduct a final review of the work provided by these third party accounting experts. There was an instance where such review process was not performed in a timely manner and as a result such third party accounting experts who were not using most up to date information reached erroneous conclusions. This instance specifically related to the annual impairment test of the Company's goodwill which was an analysis performed as of June 30, 2011.

Management's Remediation Efforts

1) Since discovering the cash flow error as part of our March 31, 2011 financial reporting process, management has worked with third party accounting experts to further improve our process for consolidating and translating our Consolidated Statement of Cash Flows.

   The Company will continue to work with its third party accounting experts to improve its process surrounding the Statement of Cash Flows including the following steps:

   - The Company plans to augment its financial reporting and technical accounting resources to enable more detailed and rigorous reviews of the cash flow statement preparation process.
   - Improved communication surrounding new or unusual transactions.
   - Conducting additional training of subsidiary personnel to assist in the preparation of documents supporting the preparation of the statement of cash flows.
   - Regular reports will be issued to the Audit Committee and Board of Directors as to the planned improvements and progress of said remediation.

2) Going forward, the Company plans to augment its financial reporting / technical accounting resources to enable more timely, detailed and rigorous reviews of documentation of the accounting implications / conclusions of complex and/or non-routine transactions, as well as recurring transactions and analyses including the preparation of the consolidated statement of cash flows.

Management and the Company's Audit Committee are fully committed to continued improvement of our internal controls over financial reporting. We have worked diligently on this matter and management believes the process improvements made and to be made will remediate the identified control deficiencies and strengthen the Company's internal controls over financial reporting. The reliability of the internal control process requires repeatable execution and as such the successful remediation of these material weaknesses will require review and evidence of effectiveness prior to management concluding that the controls are effective in our future SEC reports.

The improvement in our internal processes, in particular the Company's new consolidation process, has already demonstrated increased effectiveness and remediated an issue identified related to the Company's March 31, 2011 unaudited interim financial statements. After filing our third quarter report on Form 10-Q, we found an error that affected our March 31, 2011 financial reports. The error related to the consolidation of one of MPAL's subsidiaries. The effect of the error on the March 31, 2011 unaudited condensed consolidated financial statements was an understatement of $69,000 to exploration expense and net income included in the unaudited condensed consolidated statement of operations and an understatement of Oil and Gas assets and Accumulated Other comprehensive income of $1,633,000 and $1,702,000 respectively included in the unaudited condensed consolidated balance sheet. In light of this error, we determined that there was a material weakness in design of our processes and procedures regarding the consolidation of our foreign subsidiary, as of March 31, 2011. During the fourth quarter ended June 30, 2011 we finalized and fully implemented changes to, and improvements in the controls over our consolidation processes that were being developed over the course of the year. These new controls include the use of a new consolidation tool and having the consolidation of our Australian subsidiary performed by accounting personnel in Australia and were applied to historical financial statements as part of testing of the new controls and procedures. Our application of these controls over historical financial statements, resulted in the identification of the error in our reporting at March 31, 2011 and have fully remediated the material weakness in the controls over our consolidation process.

Limitations

Because of its inherent limitations, internal control over financial reporting and procedures may not prevent or detect misstatements. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Changes 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, 2011 that have materially affected, or are reasonable likely to materially affect the Company's internal control over financial reporting.

Item 9B. ***Other Information***

Agreements between Magellan Petroleum (N.T.) Pty Ltd and Santos QNT Pty Ltd and Santos Limited

On September 14, 2011, Magellan Petroleum (N.T.) Pty Ltd, a subsidiary of the Company, entered into a sales agreement and a gas supply and purchase agreement with Santos QNT Pty Ltd and Santos Limited. These agreements and the Santos Transaction are described in Note 20 (Subsequent Events) to the consolidated financial statements included in Item 8 of this annual report, which descriptions are hereby incorporated by reference into this Item 9B in their entirety.

Agreement between Magellan Petroleum Corporation, Nautilus Poplar, LLC, Nautilus Technical Group LLC and Eastern Rider LLC

On September 2, 2011, Magellan Petroleum Corporation, Nautilus Poplar, LLC, Nautilus Technical Group LLC and Eastern Rider LLC entered into a purchase and sale agreement. This agreement is described in Note 20 (Subsequent Events) to the consolidated financial statements included in Item 8 of this annual report, which descriptions are hereby incorporated by reference into this Item 9B in their entirety.

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 to be filed on EDGAR with respect to the fiscal year ended June 30, 2011. Certain information concerning the executive officers of the Company is included under Item 10 of this report.

Item 10. *Directors, Executive Officers and Corporate Governance*

The following is a list of the executive officers of the Company:

Name	Age	Office Held	Length of Service as an Officer	Other Positions Held with Company
William H. Hastings	56	President and Chief Executive Officer	Since 2008	None
Antoine J. Lafargue	37	Chief Financial Officer and Treasurer	Since 2010	None

For further information regarding the named executive officers, see the Company's Proxy Statement to be filed with the SEC on or about September 29, 2011.

Item 11. *Executive Compensation*

Information to be included in annual Proxy Statement.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Information to be included in annual Proxy Statement.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Information to be included in annual Proxy Statement.

Item 14. *Principal Accounting Fees and Services*

Information to be included in annual Proxy Statement.

Table of Contents

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) (1) *Financial Statements.*

The financial statements listed below and included under Item 8 are filed as part of this report.

(2) *Financial Statement Schedules.*

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

(d) *Exhibits.*

The following exhibits are filed or furnished as part of this report pursuant to Item 601 of Regulation S-K.:

Item Number

3. *Articles of Incorporation and By-Laws.*

(a) Restated Certificate of Incorporation as filed on May 4, 1987 with the State of Delaware and Amendment of Article Twelfth as filed on February 12, 1988 with the State of Delaware filed as exhibit 4(b) to Form S-8 Registration Statement, filed on January 14, 1999, are incorporated herein by reference.

(b) Certificate of Amendment to Certificate of Incorporation as filed on December 26, 2000 with the State of Delaware, filed as Exhibit 3(a) to the Company's quarterly report on Form 10-Q filed on February 13, 2001 and incorporated herein by reference.

(c) Certificate of Amendment to restated certificate of incorporation related to Article 12th as filed on October 15, 2009 with the State of Delaware, filed as exhibit 3.3 to quarterly report on Form 10-Q filed on February 16, 2010, is incorporated herein by reference.

(d) Certificate of Amendment to restated certificate of incorporation related to Article 13th as filed on October 15, 2009 with the State of Delaware, filed as Exhibit 3.4 to quarterly report on Form 10-Q filed on February 16, 2010, is incorporated herein by reference.

(e) Certificate of Amendment to restated certificate of incorporation related to Article Fourth as filed on Dec. 10, 2010, with the State of Delaware, filed as Exhibit 3.1 to current report on Form 8-K filed on Dec. 13, 2010, is incorporated herein by reference.

(f) By-Laws, as amended on March 10, 2010, as filed as Exhibit 3.1 to current Report on Form 8-K filed on March 15, 2010, are incorporated by reference.

10. *Material contracts.*

(a) Petroleum Lease No. 4 dated November 18, 1981 granted by the Northern Territory of Australia to United Canso Oil & Gas Co. (N.T.) Pty Ltd. filed as Exhibit 10(a) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(b) Petroleum Lease No. 5 dated November 18, 1981 granted by the Northern Territory of Australia to Magellan Petroleum (N.T.) Pty. Ltd. filed as Exhibit 10(b) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(c) Palm Valley Petroleum Lease (OL3) dated November 9, 1982 filed as Exhibit 10(d) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(d) Palm Valley Operating Agreement dated April 2, 1985 between Magellan Petroleum (N.T.) Pty. Ltd., C. D. Resources Pty. Ltd., Farmout Drillers N.L., Canso Resources Limited, International Oil Proprietary, Pancontinental Petroleum Limited, I.E.D.C. Australia Pty. Ltd., Southern Alloys Ventures Pty. Limited and Amadeus Oil N.L. filed as Exhibit 10(f) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(e) Mereenie Operating Agreement dated April 27, 1984 between Magellan Petroleum (N.T.) Pty., United Oil & Gas Co. (N.T.) Pty. Ltd., Canso Resources Limited, Oilmin (N.T.) Pty. Ltd., Krewliff Investments Pty. Ltd., Transoil (N.T.) Pty. Ltd. and Farmout Drillers NL and Amendment of October 3, 1984 to the above agreement filed as Exhibit 10(g) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(f) Palm Valley Gas Purchase Agreement dated June 28, 1985 between Magellan Petroleum (N.T.) Pty. Ltd., C. D. Resources Pty. Ltd., Farmout Drillers N.L., Canso Resources Limited, International Oil Proprietary, Pancontinental Petroleum Limited, IEDC Australia Pty Limited, Amadeus Oil N.L., Southern Alloy Venture Pty. Limited and Gasgo Pty. Limited. Also included are the Guarantee of the Northern Territory of Australia dated June 28, 1985 and Certification letter dated June 28, 1985 that the Guarantee is binding. All of the above were filed as Exhibit 10(h) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) and are incorporated herein by reference.

(g) Agreements dated June 28, 1985 relating to Amadeus Basin-Darwin Pipeline which include Deed of Trust Amadeus Gas Trust, Undertaking by the Northern Territory Electric Commission and Undertaking from the Northern Territory Gas Pty Ltd. filed as Exhibit 10(j) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(h) Agreement between the Mereenie Producers and the Palm Valley Producers dated June 28, 1985 filed as Exhibit 10(k) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(i) Form of Indemnification Agreement for Directors and Officers pursuant to Article SIXTEENTH of the Company's Restated Certificate of Incorporation and the Company's Bylaws, filed as Exhibit 10.1 to current report on Form 8-K filed on June 2, 2009, is incorporated herein by reference.

(j) 1998 Stock Option Plan, filed as Exhibit 4(a) to Form S-8 Registration Statement on January 14, 1999, filed as Exhibit 10(m) to Annual Report on Form 10-K for the year ended June 30, 1999 (File No. 001-5507) is incorporated herein by reference.

(k) First Amendment to the 1998 Stock Option Plan dated October 24, 2007, filed as Exhibit 10 (n) to Annual Report on Form 10-K for the year ended June 30, 2008 (File No. 001-5507) is incorporated herein by reference.

(l) Palm Valley Renewal of Petroleum Lease dated November 6, 2003, filed as Exhibit 10 (s) to Annual Report on Form 10-K for the year ended June 30, 2005, is incorporated herein by reference.

(m) Magellan Petroleum Corporation 1998 Stock Incentive Plan, as amended and restated through December 8, 2010, as filed as Exhibit 10.1 to the Company's current report on Form 8-K on December 13, 2010, is incorporated by reference herein.

(n) Form of Non-Qualified Stock Option Award Agreement for officers and directors, filed as Exhibit 10.1 to current report on Form 8-K filed on November 30, 2005, is incorporated by reference herein.

(o) Form of Amendment to Non-Qualified Stock Option Agreement for directors, December 11, 2008, filed as Exhibit 10.2 to current report on Form 8-K filed on December 15, 2008, is incorporated by reference herein.

(p) Employment Agreement between the Company and William H. Hastings, dated as of February 3, 2009, filed as Exhibit 10.1 to current report on Form 8-K filed on February 9, 2009, is incorporated by reference herein.

(q) Indemnification Agreement between the Company and William H. Hastings, dated as of February 3, 2009, filed as Exhibit 10.2 to current report on Form 8-K filed on February 9, 2009, is incorporated by reference herein.

(r) Non-Qualified Stock Option Award Agreement between the Company and William H. Hastings, dated as of February 3, 2009, filed as Exhibit 10.3 to current report on Form 8-K filed on February 9, 2009, is incorporated by reference herein.

(s) Non-Qualified Stock Option Performance Award Agreement between the Company and William H. Hastings, dated as of February 3, 2009, filed as Exhibit 10.4 to current report on Form 8-K filed on February 9, 2009, is incorporated by reference herein.

(t) Warrant Agreement between the Company and Young Energy Prize S.A, (YEP) dated July 9, 2009, filed as Exhibit 10.1 to current report on Form 8-K filed on July 14, 2009, is incorporated herein by reference.

(u) Registration Rights Agreement between the Company and YEP dated July 9, 2009, filed as Exhibit 10.2 to current report on Form 8-K filed on July 14, 2009, is incorporated herein by reference.

(v) Consulting Agreement between the Company and J. Thomas Wilson, dated July 9, 2009, filed as Exhibit 10.4 to current report on Form 8-K filed on July 14, 2009, is incorporated herein by reference.

(w) Non-qualified stock option award agreement between the Company and J. Thomas Wilson, dated July 9, 2009, filed as Exhibit 10.5 to current report on Form 8-K filed on July 14, 2009, is incorporated herein by reference.

(x) Non-qualified stock option performance award agreement between the Company and J. Thomas Wilson, dated July 9, 2009, filed as Exhibit 10.6 to current report on Form 8-K filed on July 14, 2009, is incorporated herein by reference.

(y) Amended and Restated Operating Agreement of Nautilus Poplar, between and among White Bear, the YEP I Fund, Nautilus Tech and Eastern Rider, dated as of October 14, 2009, filed as Exhibit 10.1 to current report on Form 8-K filed on October 14, 2009, is incorporated by reference herein.

(z) First Amendment to Registration Rights Agreement, between and among the Company, YEP and the YEP I Fund, dated as of October 14, 2009, filed as Exhibit 10.2 to current report on Form 8-K filed on October 14, 2009, is incorporated by reference herein.

(aa) Employment Agreement between the Company and Susan M. Filipos, dated as of August 19, 2011, filed as Exhibit 10.1 to current report on Form 8-K filed on May 7, 2010, is incorporated herein by reference.

(bb) Non-qualified Stock Option Award Agreement between the Company and Susan M. Filipos, dated as of October 1, 2009, filed as Exhibit 10.2 to current report on Form 8-K filed on May 7, 2010, is incorporated herein by reference.

(cc) Assets Sale Deed between Magellan Petroleum Australia Limited and Santos Offshore Pty Ltd., dated as of March 25, 2010, filed as Exhibit 2.1 to quarterly report on Form 10-Q filed on May 14, 2010, is incorporated herein by reference.

(dd) Amended and Restated Warrant Agreement, dated March 11, 2010, filed as Exhibit 10.1 to quarterly report on Form 10-Q filed on May 14, 2010, is incorporated herein by reference.

(ee) Form of non-qualified stock option award agreement between the Company and non-employee directors, dated April 1, 2010, filed as Exhibit 10.2 to quarterly report on Form 10-Q filed on May 14, 2010, is incorporated herein by reference.

(ff) Form of restricted stock award agreement between the Company and non-employee directors, dated April 1, 2010 (Version A), filed as Exhibit 10.3 to quarterly report on Form 10-Q filed on May 14, 2010, is incorporated herein by reference.

(gg) Form of restricted stock award agreement between the Company and non-employee directors, dated April 1, 2010 (Version B), filed as Exhibit 10.4 to quarterly report on Form 10-Q filed on May 14, 2010, is incorporated herein by reference.

(hh) Indemnification Agreement between the Company and Susan M. Filipos, dated as of May 3, 2010, filed as Exhibit 10.3 to current report on Form 8-K filed on May 7, 2010, is incorporated herein by reference.

(ii) Employment Agreement between the Company and Antoine J. Lafargue, dated as of August 2, 2010, filed as Exhibit 10.1 to current report on Form 8-K filed on August 4, 2010, is incorporated herein by reference.

(jj) Indemnification Agreement between the Company and Antoine J. Lafargue, dated as of August 2, 2010, filed as Exhibit 10.2 to current report on Form 8-K filed on August 4, 2010, is incorporated herein by reference.

(kk) Non-Qualified Stock Option Award Agreement between the Company and Antoine J. Lafargue, dated as of August 2, 2010, filed as Exhibit 10.3 to current report on Form 8-K filed on August 4, 2010, is incorporated herein by reference.

(ll) Non-Qualified Stock Option Performance Award Agreement between the Company and Antoine J. Lafargue, dated as of August 2, 2010, filed as Exhibit 10.4 to current report on Form 8-K filed on August 4, 2010, is incorporated herein by reference.

(mm) Securities Purchase Agreement between the Company and YEP., dated August 5, 2010, filed as Exhibit 10.1 to current report on Form 8-K filed on Aug. 11, 2010, is incorporated herein by reference.

(nn) Memorandum of Agreement between the Company and YEP, dated August 5, 2010, filed as Exhibit 10.2 to current report on Form 8-K filed on Aug. 11, 2010, is incorporated herein by reference.

(oo) Investor Rights Agreement, between the Company and YEP, dated August 5, 2010, filed as Exhibit 10.3 to current report on Form 8-K filed on Aug. 11, 2010, is incorporated herein by reference.

Table of Contents

(pp) Letter Deed, dated December 23, 2010 between Magellan Petroleum Australia Limited and Santos Offshore Pty Ltd., filed as Exhibit 10.1 to Current Report on Form 8-K filed on Dec. 28, 2010, is incorporated herein by reference.

(qq) Deed of Variation between Magellan Petroleum Australia Limited and Santos Offshore Pty Ltd. dated as of January 31, 2011, filed as Exhibit 10.1 to Quarterly Report on Form 10-Q filed on May 16, 2011, is incorporated herein by reference.

(rr) Letter of YEP to the Company, dated January 13, 2011, effective as of December 23, 2010, filed as Exhibit 10.1 to Current Report on Form 8-K filed on Jan. 18, 2011, is incorporated herein by reference.

(ss) Second Amendment to Registration Rights Agreement between and among the Company, YEP and the ECP Fund, SICAV-FIS, dated June 23, 2010, filed as Exhibit 10(xx) to Annual Report on Form 10-K for the year ended June 30, 2010, is incorporated herein by reference.

(tt) First Amendment to Securities Purchase Agreement between the Company and YEP, dated February 11, 2011, filed as Exhibit 10.1 to Current Report on Form 8-K filed on February 18, 2011, is incorporated herein by reference.

(uu) Second Amendment to Securities Purchase Agreement between the Company and YEP, dated February 17, 2011, filed as Exhibit 10.2 to Current Report on Form 8-K filed on February 18, 2011, is incorporated herein by reference.

(vv) Investment Agreement between the Company and YEP, dated February 11, 2011, filed as Exhibit 10.3 to Current Report on Form 8-K filed on February 18, 2011, is incorporated herein by reference.

(ww) Amended Side Letter to Investment Agreement between the Company and YEP, dated February 17, 2011, filed as Exhibit 10.4 to Current Report on Form 8-K filed on February 18, 2011, is incorporated herein by reference.

14. Code of Ethics

Magellan Petroleum Corporation Standards of Conduct filed as Exhibit 14 to Annual Report Form 10-K for the year ended June 30, 2006, is incorporated herein by reference.

21. Subsidiaries of the registrant is filed herewith.

23. Consent of experts and counsel.

1. Consent of Deloitte & Touche LLP is filed herewith.

2. Consent of Allen & Crouch Petroleum Engineers Inc. is filed herewith.

3. Consent of Ryder Scott Company, L.P. is filed herewith.

31. Rule 13a-14(a) Certifications.

31.1 Certification of William H. Hastings, President and Chief Executive Officer, pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, is filed herewith.

31.2 Certification of Antoine J. Lafargue, Chief Financial and Accounting Officer, pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, is filed herewith.

Table of Contents

32. Section 1350 Certifications.

32.1 Certification of William H. Hastings, President and Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, is furnished herewith.

32.2 Certification of Antoine J. Lafargue, Chief Financial and Accounting Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, is furnished herewith.

99.1 Summary reserves report of Allen & Crouch Petroleum Engineers Inc., is filed herewith.

99.2 Summary reserves report of Ryder Scott Company, L.P. is filed herewith.

Table of Contents

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/ WILLIAM H. HASTINGS
William H. Hastings
President and Chief Executive Officer
(Duly Authorized Officer)

By /s/ ANTOINE J. LAFARGUE
Antoine J. Lafargue
Chief Financial Officer and Treasurer
(as Principal Financial and Accounting Officer)

Dated: September 20, 2011

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/ WILLIAM H. HASTINGS William H. Hastings	President and Chief Executive Officer	Dated: September 20, 2011
/S/ ANTOINE J. LAFARGUE Antoine J. Lafargue	Chief Financial Officer and Treasurer	Dated: September 20, 2011
/S/ DONALD V. BASSO Donald V. Basso	Director	Dated: September 20, 2011
/S/ NIKOLAY V. BOGACHEV Nikolay V. Bogachev	Director	Dated: September 20, 2011
/S/ ROBERT J. MOLLAH Robert J. Mollah	Director	Dated: September 20, 2011
/S/ WALTER MCCANN Walter McCann	Director	Dated: September 20, 2011
/S/ RONALD P. PETTIROSSI Ronald P. Pettirossi	Director	Dated: September 20, 2011
/S/ J. THOMAS WILSON J. Thomas Wilson	Director	Dated: September 20, 2011
/S/ J. ROBINSON WEST J. Robinson West	Director	Dated: September 20, 2011

INDEX TO EXHIBITS

21	Subsidiaries of the Registrant.
23	1. Consent of Deloitte & Touche LLP
	2. Consent of Allen & Crouch Petroleum Engineers Inc.
	3. Consent of Ryder Scott Co. L.P.
31	Rule 13a-14(a) Certifications.
32	Section 1350 Certifications.
99	1. Summary Reserves Report of Allen & Crouch, Inc.
	2. Summary Reserves Report of Ryder Scott Co. L.P.

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

(As of June 30, 2011)

Subsidiary	State of Incorporation	Ownership
Nautilus Poplar, LLC		83.50%
Magellan Petroleum Australia Limited	Queensland, Australia	100.00%
Magellan Petroleum Australia Limited owns the following subsidiaries directly or indirectly:		
Magellan Petroleum (N.T.) Pty. Ltd.	Queensland, Australia	100.00%
Paroo Petroleum Pty. Ltd.	Queensland, Australia	100.00%
Paroo Petroleum (Holdings), Inc.	Delaware, U.S.A.	100.00%
Paroo Petroleum (USA), Inc.	Delaware, U.S.A.	100.00%
Magellan Petroleum (W.A.) Pty. Ltd.	Queensland, Australia	100.00%
Magellan Petroleum (U.K.) Limited	United Kingdom	100.00%
Magellan Petroleum (Eastern) Pty. Ltd.	Queensland, Australia	100.00%
United Oil & Gas Co. (N.T.) Pty. Ltd.	Queensland, Australia	100.00%
Magellan Petroleum (Qld.) Pty. Ltd.	Queensland, Australia	80.00%
Magellan Petroleum (Offshore) Pty. Ltd.	Queensland, Australia	100.00%
Jarl Pty. Ltd.	Queensland, Australia	100.00%

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-70567 on Form S-8 of our reports dated September 20, 2011, relating to the consolidated financial statements of Magellan Petroleum Corporation and subsidiaries (which report included an explanatory paragraph relating to the adoption of Accounting Standards Update No. 2010-3, "*Oil and Gas Reserve Estimation and Disclosures*") and internal control over financial reporting (which report expressed an adverse opinion on the effectiveness of the Magellan Petroleum Corporation and subsidiaries internal control over financial reporting because of material weaknesses), appearing in this Annual Report on Form 10-K of Magellan Petroleum Corporation and subsidiaries for the year ended June 30, 2011.

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

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned firm of Independent Petroleum Engineers, of Casper, Wyoming, United States, knows that it is named as having prepared an audit of a constant dollar reserves evaluation prepared by Nautilus Poplar LLC dated August 19, 2011 of the Montana interests of Magellan Petroleum Corporation, and hereby gives its consent to the use of its name and to the use of the said estimates.

Allen & Crouch Petroleum Engineers, Inc.

/s/ Richard L. Vine, P.E.

Richard L. Vine, P.E.

August 19, 2011

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned firm of Independent Petroleum Engineers, of Denver, Colorado, United States, knows that it is named as having prepared a constant dollar evaluation dated July 17, 2011 of the Australian interests of Magellan Petroleum Corporation, and hereby gives its consent to the use of its name and to the use of the said estimates.

Ryder Scott Company

/s/ Ryder Scott Company, L.P.

August 16, 2011

Exhibit 31.1

RULE 13A-14(a) CERTIFICATIONS

I, William H. Hastings, certify that:

1. I have reviewed this annual report on Form 10-K of Magellan Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrants other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15a-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ WILLIAM H. HASTINGS

William H. Hastings
President and Chief Executive Officer

Dated: September 20, 2011

Exhibit 31.2

RULE 13A-14(a) CERTIFICATIONS

I, Antoine J. Lafargue, certify that:

1. I have reviewed this annual report on Form 10-K of Magellan Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrants other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15a-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ ANTOINE J. LAFARGUE

Antoine J. Lafargue
Chief Financial Officer and Treasurer

Dated: September 20, 2011

Exhibit 32.1

SECTION 1350 CERTIFICATIONS

In connection with the Annual Report of Magellan Petroleum Corporation (the "Company") on Form 10-K for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William H. Hastings, President and Chief Executive Officer of the Company, do hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/S/ WILLIAM H. HASTINGS

William H. Hastings

President and Chief Executive Officer

Dated: September 20, 2011

Exhibit 32.2

SECTION 1350 CERTIFICATIONS

In connection with the Annual Report of Magellan Petroleum Corporation (the "Company") on Form 10-K for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Antoine J. Lafargue, Chief Financial Officer and Treasurer of the Company, do hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/S/ ANTOINE J. LAFARGUE

Antoine J. Lafargue
Chief Financial Officer and Treasurer

Dated: September 20, 2011

Exhibit 99.1

August 19, 2011

Ms. Susan Filipos
Magellan Petroleum Corporation
7 Custom House Street, 3rd Floor
Portland, Maine, 04101

Re: Magellan Petroleum Corporation
Allen & Crouch Audit of the Nautilus
Reserve and Economic Evaluation of
Interests in the Poplar East Unit and
Poplar Northwest Field
Roosevelt County, MT

Dear Ms. Filipos:

In accordance with the request of Mr. Wayne Kahmeyer with Nautilus Poplar LLC (Nautilus), an engineering audit was performed on behalf of Magellan Petroleum Corporation (Magellan) to review the reserves and corresponding net present value of working interests owned in the East Poplar Unit and the Poplar Northwest Field, Roosevelt County, MT. The reserves evaluation was prepared by Naing Aye with Nautilus Poplar LLC. The report was prepared for public disclosure by Magellan Petroleum Corporation in filings made with the SEC in accordance with the disclosure requirements set forth in SEC regulations. The evaluation included proved developed producing (PDP) reserves attributable to currently producing wells, proved developed non producing (PDNP) reserves associated with pump upsizing, current zone stimulations and recompletions, proved undeveloped (PUD) reserves associated with development of the Charles formation and probable undeveloped reserves (PRB) associated with development of the Tyler formation. The effective date of the evaluation is June 30, 2011. This evaluation was prepared using constant prices and costs and conforms to our understanding of the U.S. Securities and Exchange Commission (SEC) guidelines and applicable financial accounting rules. All prices, costs and cash flow estimates are expressed in U.S. dollars (US$). The reserves and future net revenue are net to the combined interests of Magellan and Nautilus. We believe the assumptions, data, methods and procedures used in preparing this report are appropriate for the purpose of this report. Allen & Crouch has reviewed 100% of Magellan's US reserves.

Table 1 summarizes the estimates of the net reserves and future net revenues, as of June 30, 2011 for the Magellan evaluated properties. Unescalated prices and costs were used for all properties contained in this evaluation.

Table 1

Estimated Net Reserves and Future Net Revenue
Certain Proved and Probable Oil and Gas Interests
Magellan Petroleum Corporation
East Poplar Unit and NW Poplar Fields
As of June 30, 2011

	Proved			Total	
	Producing Reserves	Non-Producing Reserves	Undeveloped Reserves	Proved Reserves	Probable Reserves
Remaining Net Reserves					
Oil/Cond/Ngl—Bbls	1,127,380	1,122,190	6,940,870	9,190,440	1,824,080
Gas—MMscf	0	0	0	0	0
Income Data ($)					
Future Net Revenue	90,111,290	89,697,040	554,784,030	734,592,360	145,798,430
Deductions					
Operating Expense	49,524,280	31,016,660	105,005,430	136,022,090	31,257,750
Production Taxes	14,341,170	14,351,530	88,765,440	117,458,140	23,327,750
Investment	1,502,720	2,659,240	24,687,000	28,848,960	4,646,300
Future Net Cashflow	24,743,130	41,669,620	336,326,150	402,738,900	86,566,620
Discounted PV @ 10% ($)	10,705,630	17,868,650	151,289,230	179,863,510	24,179,530

Values in the tables of this report may not add up arithmetically due to the rounding procedure in the computer software program used to prepare the economic projections. All hydrocarbon liquids are reported as 42 gallon barrels.

Allen & Crouch Petroleum Engineers, Inc. is an independent petroleum engineering firm with respect to Magellan, as provided in the Society of Petroleum Engineers', "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves". Allen & Crouch neither owns an interest in any Magellan properties, nor is employed by them on a retainer or contingent basis.

Oil and gas reserves by definition fall into one of the following categories: proved, probable, and possible. The proved category is further divided into: developed and undeveloped. The developed reserve category is even further divided into the appropriate reserve status subcategories: producing and non-producing. Non-producing reserves include shut-in and behind-pipe reserves. The reserves included in this report include proved and probable reserves. The reserves and income attributable to the various reserve categories included in this report have not been adjusted to reflect the varying degrees of risk associated with them.

Reserve estimates are strictly technical judgments. The accuracy of any reserve estimate is a function of the quality and the quantity of data available and of the engineering and geological interpretations. The reserve estimates presented in this report are believed reasonable; however, they are estimates only and should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify their revision. A portion of these reserves are for non-producing wells that lack sufficient production history to utilize conventional performance-based reserve estimates. In these cases, the reserves are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. Actual future prices may vary significantly from the prices used in this evaluation; therefore, future hydrocarbon volumes recovered and the income received from these volumes may vary significantly from those estimated in this report. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

A portion of these reserves are for undeveloped acreage. Reserves for these cases are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. The proved undeveloped (PUD) reserves are based upon developmental drilling in the Charles formation. The production forecast is based upon a typecurve of historical production from existing Charles wells in the area. The probable undeveloped (PRB) reserves are based upon development drilling in the Tyler formation. The production forecast is based upon Tyler production from the EPU #7 well. Probable reserves estimates are subject to an greater degree of uncertainty than proved reserves.

Allen & Crouch has used all methods and procedures it considers necessary under the circumstances in the audit of these reserves evaluations. The appropriate combination of conventional decline curve analysis (DCA), production data analysis and type curves were used to estimate the remaining reserves in the various producing areas. All assumptions, data, methods and procedures used in the preparation of this report were appropriate for the purpose served by the report.

All prices used in preparation of this report were based on twelve month unweighted arithmetic average of the first day of the month price for the period July 2010 through June 2011. The resulting oil price used was $79.93/Bbl. This price was adjusted for local differentials and gravity. As required by the SEC guidelines, all pricing was held constant for the life of the projects (no escalation).

Operating costs used in this report were based on values reported by Nautilus and reviewed by Allen & Crouch. Nautilus's estimates for capital costs for all non-producing wells are included in the evaluation. Magellan and Nautilus have indicated to us that they have the ability and intent to implement their capital expenditure program as scheduled. Operating costs and capital costs were held constant for the life of the projects (no escalation).

Net revenue (sales) is defined as the total proceeds from the sale of oil, condensate, natural gas liquids (NGL), and gas adjusted for the commodity price basis differential and gathering/transportation expense. Future net income (cashflow) is future net revenue less net lease operating expenses, state severance or production taxes, operating/development capital expenses and net salvage. Future plugging, abandonment and salvage costs are considered in this report. No provisions for State or Federal income taxes have been made in this evaluation. The present worth (discounted cashflow) at various discount rates is calculated on a monthly basis.

In the conduct of our evaluation, we have not independently verified the accuracy and completeness of information and data furnished by Nautilus with respect to ownership, interests, costs of operation and development, product prices, payout balances and agreements relating to current and future operations and sales of production. If in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of the information or data provided by Nautilus, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

Nautilus' operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

In our opinion, the above-described estimates of Magellan's proved reserves and supporting data are, in the aggregate, reasonable. There was no aggregate difference larger than 10%. It is also our opinion that the above-described estimates of Magellan's proved reserves conform to the definitions of proved, probable and possible oil and gas reserves promulgated by the SEC.

All data used in this study were obtained from Nautilus or the non-confidential files of Allen & Crouch. A field inspection of the properties was not made in connection with the preparation of this report. The potential environmental liabilities attendant to ownership and/or operation of the properties have not been addressed in this report. Abandonment and clean-up costs and possible salvage value of the equipment were considered in this report.

Data and worksheets used in the preparation of this evaluation will be maintained in our files in Casper and will be available for inspection by anyone having proper authorization from Magellan.

Thank you for the opportunity to perform this audit. If you have any questions or require additional information regarding the evaluation, please don't hesitate to call.

Sincerely,

/s/ Richard L. Vine, P.E.

Richard L. Vine, P.E.
Wyoming License No. 10041
Allen & Crouch Petroleum Engineers, Inc.

Exhibit 99.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

July 17, 2011

Magellan Petroleum Corp.
7 Custom House Street, 3rd Floor
Portland, ME 04101

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved and probable reserves, future production, and income attributable to certain leasehold interests. The subject properties are located in the country of Australia. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on July 17, 2011 and presented herein, was prepared for public disclosure by Magellan Petroleum Corp. in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved and probable liquid hydrocarbon reserves and 100 percent of the total net proved and probable gas reserves of Magellan Petroleum Australia Limited, a wholly owned subsidiary of Magellan Petroleum Corp as of June 30, 2011.

The estimated reserves and future net income amounts presented in this report, as of June 30, 2011 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Magellan Petroleum Corp.
As of June 30, 2011

	Proved	
	Developed Producing	Total Proved
Net Remaining Reserves		
Oil/Condensate – Barrels	0	0
Gas — MMCF	430	430
Income Data		
Future Gross Revenue	$804,101	$804,101
Deductions	531,785	531,785
Future Net Income (FNI)	$272,316	$272,316
Discounted FNI @ 10%	$264,023	$264,023

	Probable			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Probable
Net Remaining Reserves				
Oil/Condensate – Barrels	575,233	0	666,400	1,241,633
Gas — MMCF	16,108	3,628	0	19,736
Income Data				
Future Gross Revenue	$129,904,640	$16,473,315	$55,945,842	$202,323,797
Deductions	62,497,853	6,801,529	28,536,708	97,836,090
Future Net Income (FNI)	$ 67,406,787	$ 9,671,786	$27,409,134	$104,487,707
Discounted FNI @ 10%	$ 33,389,488	$ 3,763,015	$11,805,791	$ 48,958,294

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of royalties, which are treated as a production tax since they are based on the well head value of the royalty and the royalty owners have no right to take the royalty in-kind. The deductions incorporate the normal direct costs of operating the wells, recompletion costs and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of total future gross revenue from proved reserves. Liquid hydrocarbon reserves account for approximately 53 percent and gas reserves account for the remaining 47 percent of total future gross revenue from probable reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of June 30, 2011	
Discount Rate Percent	Total Proved	Total Probable
5	$268,121	$71,107,431
8	$265,650	$56,769,286
12	$262,410	$42,284,883
15	$260,019	$34,021,192

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved and probable reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The probable developed non-producing reserves included herein consist of the shut in category. No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved and probable gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable or possible reserves to denote progressively increasing uncertainty in their recoverability. At Magellan Petroleum Corp.'s request, this report addresses the proved and probable reserves attributable to the properties evaluated herein.

Proved gas reserves are those quantities of gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." Probable reserves are "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered."

The reserves included herein were estimated using deterministic methods. Under the deterministic approach, discrete quantities of reserves are estimated and assigned separately as proved or probable based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

Reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved and probable reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and probable reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

The proved reserves reported herein are limited to the period prior to expiration of current gas sales contracts. The probable reserves were limited to the contract provisions being proposed in term sheets currently being negotiated with gas purchasers.

This report includes certain volumes of proved and probable reserves attributable to royalties owed to the host government that are treated as taxes to be paid in cash.

Magellan Petroleum Australia Limited's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved and probable reserves actually recovered and amounts of proved and probable income actually received to differ from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Magellan Petroleum Corp. owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved and/or probable that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved and probable reserves for the properties included herein were estimated by performance methods and analogy. Approximately 100 percent of the proved and 100 percent of the probable producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The performance method utilized was decline curve analysis which utilized extrapolations of historical production data available through April, 2011. The data utilized in this analysis were furnished to Ryder Scott by Magellan Petroleum Australia Limited and were considered sufficient for the purpose thereof.

Approximately 100 percent of the probable developed non-producing reserves included herein were also estimated by the performance method and 100 percent of the probable undeveloped reserves were estimated by analogy. The data utilized from the analogue wells were considered sufficient for the purpose thereof.

To estimate economically recoverable proved and probable oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved and probable reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Magellan Petroleum Australia Limited has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved and probable production and income, we have relied upon data furnished by Magellan Petroleum Australia Limited with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Magellan Petroleum Australia Limited. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved and probable reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved and probable reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Magellan Petroleum Australia Limited. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Magellan Petroleum Australia Limited furnished us with the above mentioned average prices in effect on June 30, 2011. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements. For the probable gas reserves the price the gas price utilized was the volume weighted annual price based on the contract prices contained in the latest available term sheets.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were estimated by us based on information furnished by Magellan Petroleum Australia Limited.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before any deductions and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Avg Benchmark Prices	Avg Proved Realized Prices	Avg Probable Realized Prices
Australia	Oil/Condensate	WTI Cushing	$90.09/Bbl		$ 97.69/Bbl
	Gas	Contract Prices		$2.26/MCF	$5.46/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Magellan Petroleum Australia Limited and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs used in the preparation of this report were estimated by us based on information furnished by Magellan Petroleum Australia Limited. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Magellan Petroleum Australia Limited and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. Magellan Petroleum Australia Limited provided abandonment costs net of salvage. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Magellan Petroleum Australia Limited's estimate.

The probable developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Magellan Petroleum Australia Limited's plans to develop these reserves as of June 30, 2011. The implementation of Magellan Petroleum Australia Limited's development plans as presented to us and incorporated herein is subject to the approval process adopted by Magellan Petroleum Australia Limited's management. As the result of our inquiries during the course of preparing this report, Magellan Petroleum Australia Limited has informed us that the development activities included herein have been subjected to and received the internal approvals required by Magellan Petroleum Australia Limited's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Magellan Petroleum Australia Limited. Additionally, Magellan Petroleum Australia Limited has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Magellan Petroleum Australia Limited were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Magellan Petroleum Corp. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Magellan Petroleum Corp.

We have provided Magellan Petroleum Corp. with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Magellan Petroleum Corp. and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Larry T. Nelms

Larry T. Nelms, P.E.
Managing Senior Vice President

[SEAL]

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Larry Thomas Nelms is the primary technical person responsible for the estimate of the reserves, future production and income.

Nelms, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1983, is a Managing Senior Vice President and also serves as a member of the Board of Directors, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Nelms served in a number of engineering positions with Dome Petroleum, Mizel Petro Resources and Exxon. For more information regarding Mr. Nelms' geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Nelms earned a Bachelor of Science degree in Mechanical Engineering from Mississippi State University in 1963 and a Master of Science from the University of New Mexico in 1965, and he is a registered Professional Engineer in the State of Colorado. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, where he serves as chairman of the Denver Section and also served for three years on the board of directors.

As part of his 2009 continuing education hours, Nelms attended an internally presented 16 hours of formalized training as well as the day long 2009 RSC Reserves Conference forum, and a presentation at the Denver Section of SPEE by Dr. John Lee relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Nelms serves as the instructor of the PetroSkills course entitled "Oil & Gas Reserve Evaluation" for a period of four years.

Based on his educational background, professional training and more than 25 years of practical experience in the estimation and evaluation of petroleum reserves, Nelms has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS