Rosetta Resources Inc.
Form 10-K
February 26, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
For The Fiscal Year Ended December 31, 2012

OR

¨ **Transition Report Pursuant To Section 13 Or 15(d) of the Securities Exchange Act of 1934**
Commission File Number: 000-51801

ROSETTA RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**43-2083519** **(I.R.S. Employer Identification No.)**
717 Texas, Suite 2800, Houston, TX	**77002**

(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: (713) 335-4000

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, $.001 Par Value	The Nasdaq Stock Market LLC (Nasdaq Global Select Market)
(Title of Class)	(Name of Exchange on which registered)

Securities Registered Pursuant to Section 12 (g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No x

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 x 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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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. x

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.

Large accelerated filer x	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 x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 29, 2012 was approximately $1.9 billion based on the closing price of $36.62 per share on the Nasdaq Global Select Market.

The number of shares of the registrant s Common Stock, $.001 par value per share, outstanding as of February 8, 2013 was 52,635,356.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2013 annual meeting of stockholders to be filed with the Securities and Exchange Commission are incorporated by reference in answer to Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, would , exp plan, project, intend, anticipate, believe, estimate, predict, potential, pursue, target or continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations for the future, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in Part I of this report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances, or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, natural gas liquids (NGLs) and natural gas;
- changes in the price of oil, NGLs and natural gas;
- general economic conditions, either internationally, nationally or in jurisdictions where we conduct business;
- conditions in the energy and financial markets;
- our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;
- the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the occurrence of property acquisitions or divestitures;
- reserve levels;

inflation;

competition in the oil and natural gas industry;

the availability and cost of relevant raw materials, goods and services;

the availability and cost of processing and transportation;

changes or advances in technology;

potential reserve revisions;

limitations, availability, and constraints on infrastructure required to transport, process and market oil, NGLs and natural gas;

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performance of contracted markets, and companies contracted to provide transportation, processing and trucking of oil, NGLs and natural gas;

developments in oil-producing and natural gas-producing countries;

drilling and exploration risks;

legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, changes in national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, environmental regulations and environmental risks and liability under federal, state and local environmental laws and regulations;

effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

present and possible future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;

the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;

factors that could impact the cost, extent and pace of executing our capital program, including but not limited to, access to oilfield services, access to water for hydraulic fracture stimulations and permitting delays, unavailability of required permits, lease suspensions, drilling, exploration and production moratoriums and other legislative, executive or judicial actions by federal, state and local authorities, as well as actions by private citizens, environmental groups or other interested persons;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers; and

any other factors that impact or could impact the exploration of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

For a listing of oil and natural gas terms used in this report, see Glossary of Oil and Natural Gas Terms at the end of this report.

Part I

Items 1 and 2. Business and Properties

General

We are an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. Our operations are primarily located in South Texas, including our largest producing area in the Eagle Ford area. Our headquarters are located in Houston, Texas and we have field offices in Catarina and Smiley, Texas.

Rosetta Resources Inc. (together with its consolidated subsidiaries, we, our, us, the Company, Rosetta or like terms) was incorporated in Delaware in June 2005. We have grown our property base by developing and exploring our acreage, purchasing new undeveloped leases, acquiring oil and natural gas producing properties and drilling prospects from third parties and strategically divesting certain assets that were more gas-based. We operate in one geographic operating segment. See Item 8. Financial Statements and Supplementary Data, Note 15 Operating Segments.

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Our Strategy

Our strategy is to increase shareholder value by delivering sustainable growth from unconventional onshore domestic basins through sound stewardship, wise capital resource management, taking advantage of business cycles and emerging trends and minimizing liabilities through governmental compliance and protecting the environment. Below is a discussion of the key elements of our strategy.

Leverage high-grade asset base. The Eagle Ford area has become our largest producing location providing approximately 96% of our total production for 2012. In addition, approximately 60% of the production from the Eagle Ford area in 2012 was from crude oil and NGLs. Our extensive inventory of investment opportunities in the Eagle Ford area provides higher economic returns than areas in which we have sold assets during the last few years. The Eagle Ford area has become a major source of our production and reserves and reflects the success of our transition to an unconventional resource player.

Successfully execute our business plan. We manage all elements of our cost structure, including drilling and operating costs, as well as overhead costs. We strive to minimize our drilling and operating costs by concentrating our activities within existing and new unconventional resource play areas where we can achieve efficiencies through economies of scale. As part of our strategy to minimize costs, we have taken aggressive steps to ensure access to transportation and processing facilities, specifically within the Eagle Ford area, a region where midstream services are in high demand and infrastructure is under construction.

Test future growth opportunities. Our strategy involves the potential deployment of free cash flow expected to be generated by our existing Eagle Ford area assets in the near term for the acquisition of assets and leasehold positions in the Eagle Ford area, as well as new basins. In this regard, we intend to maintain, further develop and apply the technological expertise that helped us achieve a net drilling success rate of 100% in 2012 and helped us establish a major production base in the Eagle Ford area. We use advanced geological and geophysical technologies, detailed petrophysical analyses, advanced reservoir engineering and sophisticated drilling, completion and stimulation techniques to grow our reserves, production and project inventory. We intend to extend our operational footprint in the Eagle Ford area, as well as into new areas within the United States characterized by a significant presence of resource potential that can be exploited utilizing our technological expertise. We strive to minimize the cost of entry into these plays through financial discipline in our leasehold acquisition activities and prudent management of financial and operational resources during the testing phase.

Maintain Financial Strength and Flexibility. As of December 31, 2012, we had drawn $210.0 million and had $415.0 million available for borrowing under our Amended and Restated Senior Revolving Credit Facility (the Credit Facility). We expect internally generated cash flows, supplemented by borrowings under our Credit Facility, to provide financial flexibility to further develop our assets in the next few years. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our oil, NGL and natural gas production. As of December 31, 2012, we have entered into a series of commodity derivative contracts through 2015 as part of this strategy and in early 2013, we borrowed an additional $15.0 million under the Credit Facility, thereby reducing our borrowing capacity to $400.0 million.

Our Operating Area and Other Plays

We own producing and non-producing oil and natural gas properties in proven or prospective basins that are primarily located in South Texas. In 2012, we drilled 85 gross and 82 net wells, with a success rate of 100%.

As of December 31, 2012, we owned approximately 72,000 net acres in South Texas. Our production in South Texas comes primarily from the Eagle Ford area, which averaged 35.9 MBoe per day in 2012, an increase of 67% from the prior year. In 2012, our production from properties outside of the Eagle Ford area declined 78% from the prior year to an average of 1.3 MBoe per day. Most of our production outside of the Eagle Ford area has now been sold as part of our divestiture activities.

The Eagle Ford area has become our largest producing area where we hold approximately 67,000 net acres, with 53,000 net acres located in the liquids-rich area of the play. Our 2012 activities were focused in four areas

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of the Eagle Ford, including the Gates Ranch, Karnes Trough, Dimmit County and Briscoe Ranch areas. We drilled 79 gross and 76 net development wells in the Eagle Ford area in 2012, all of which were successful. We also drilled one gross exploratory well located in the central Dimmit County area on our Lasseter & Eppright acreage. For 2012, the Eagle Ford area provided approximately 96% of our total production. In addition, approximately 60% of our production mix from the Eagle Ford area in 2012 was attributable to crude oil and NGLs.

In 2012, we drilled three gross wells in the Southern Alberta Basin in Northwest Montana. During the second quarter of 2012, we concluded our exploratory drilling program in this play. Of the seven horizontal wells that were drilled in 2011 and 2012, five were completed. Based on results that were not economic, we have suspended all capital activity for exploration in the area. Our Southern Alberta Basin leases and lease options will begin to expire in January 2014.

In addition to our focus in the Eagle Ford area, we are pursuing new opportunities to drive the long-term growth and sustainability of the Company. In late 2012, we drilled two gross exploratory wells as part of this initiative. One exploratory well is located inside of the Eagle Ford area in the Hanks area in LaSalle County where we are testing the Pearsall shale. We will continue to consider investments in other unconventional resource basins that offer a viable inventory of projects including new higher-risk exploration projects and producing property acquisitions.

Divestiture Activities

As part of our strategic decision to focus on the Eagle Ford area, we divested certain gas-based assets that we believe did not offer the same investment opportunities or rates of return as our unconventional resources. The divestitures of these properties were not material to our operations but affect the comparability of our results between periods. In 2012, we closed on the sale of our Lobo assets and a portion of our Olmos assets located in South Texas for $95 million. In 2011, we divested our assets located in the DJ Basin in Colorado and the Sacramento Basin in California for $255 million. In 2010, we divested certain assets located in Arkansas, Oklahoma, Mississippi, Texas, Louisiana, New Mexico and Wyoming for approximately $90 million. These divestitures were all subject to post-closing adjustments. See Item 8. Financial Statements and Supplementary Data, Note 4 Property and Equipment, Net.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens on at least 80% of our proved reserves in accordance with our Credit Facility. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we generally have satisfactory title to or rights in all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the oil and natural gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

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Crude Oil, NGL and Natural Gas Operations

Production by Operating Area

The following tables present certain information with respect to our production data for the periods presented:

	Year Ended December 31, 2012			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (1)
Eagle Ford	3,445.0	4,390.9	31,716.9	13,122.1
South Texas	12.0	80.6	2,109.6	444.2
Other	39.6	0.4	26.4	44.3
Total	3,496.6	4,471.9	33,852.9	13,610.6

	Year Ended December 31, 2011			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (1)
Eagle Ford	1,747.4	2,396.2	22,057.4	7,824.2
South Texas	43.0	247.1	6,968.4	1,448.4
California	43.7		3,439.6	617.0
Rockies	9.5		862.3	153.2
Gulf Coast	19.6		62.0	29.2
Other Onshore	0.1		3.6	0.1
Total	1,863.3	2,643.3	33,393.3	10,072.1

	Year Ended December 31, 2010			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (1)
Eagle Ford	536.0	690.0	6,606.3	2,329.8
South Texas	68.0	381.0	11,197.6	2,311.6
California	27.0		13,611.1	2,295.3
Rockies	21.0	1.0	6,583.2	1,120.2
Gulf Coast	47.0	15.0	522.3	148.5
Other Onshore	39.0	9.0	689.7	163.6
Total	738.0	1,096.0	39,210.2	8,369.0

(1) Oil equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or NGLs.

For additional information regarding our oil, NGL and natural gas production, production prices and production costs, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Proved Reserves

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as reservoir performance, commodity pricing, and expected recovery rates associated with infill drilling. Therefore, the reserve information in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be

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measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil, NGLs and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

As of December 31, 2012, we had an estimated 201 MMBoe of proved reserves, of which 37% was proved developed. Based on the twelve-month first-day-of-the-month historical average prices for 2012, as adjusted for basis and quality differentials, for West Texas Intermediate oil of $91.21 per Bbl and Henry Hub natural gas of $2.76 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of $1.8 billion as of December 31, 2012.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2012:

	Estimated Proved Reserves at December 31, 2012 (1)(2)									
	Developed				Undeveloped					
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Total (MMBoe)	Percent of Total Reserves
Eagle Ford	19.3	25.0	177.4	73.9	25.1	46.5	331.2	126.8	200.7	100%
Other		0.1	0.8	0.2					0.2	0%
Total	19.3	25.1	178.2	74.1	25.1	46.5	331.2	126.8	200.9	100%

(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the Securities and Exchange Commission (SEC) guidelines and audited by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates and Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures. NSAI s report is attached as Exhibit 99.1 to this Form 10-K.

(2) The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average price, calculated as the twelve-month first-day-of-the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

All of our proved undeveloped reserves at December 31, 2012 are scheduled for development within five years from the date first recorded as a proved undeveloped reserve.

In 2012, we added 65.6 MMBoe of proved reserves in the Eagle Ford area by drilling and completing 37 successful wells and adding 54 proved undeveloped locations. The significant addition of proved reserves primarily resulted from the completion of 15 producing wells and the addition of 47 proved undeveloped locations in the Gates Ranch area. We also added proved reserves in 2012 at Adele Dubose (two proved producing), Briscoe Ranch (three proved producing and five proved undeveloped), Klotzman (14 proved developed), Lasseter & Eppright (one proved developed), and Light Ranch (two proved developed and two proved undeveloped). We spent approximately $195 million in 2012 for the development of 20 MMBoe of proved undeveloped reserves from 25 wells in the Gates Ranch area, reflecting development of 28% of our 2011 year-end proved undeveloped reserves. Four wells on the Gates Ranch that were more than one location away from a 2011 producing well were also successfully completed and producing in 2012.

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We initially delineated the Gates Ranch area by drilling 17 delineation wells from late 2009 through 2010. Initial development of the Gates Ranch area was on approximately 100-acre well spacing to prove that there was a continuous accumulation of hydrocarbons in this area and to gather production data to determine the correct well spacing for future development. Based upon the results of several pilot wells drilled on approximately 55-acre spacing, as well as decline curve analysis, rate time analysis, rate cumulative analysis, the lack of production interference between wells and estimates of recoverable hydrocarbons, we adjusted well spacing to approximately 55 acres in 2012 in the majority of the Gates Ranch area (as allowed under Texas regulatory rules for the Eagle Ford). All but seven wells drilled and completed in the Gates Ranch area in 2012 were based on the approximate 55-acre spacing between wells. In the Gates Ranch area, all 148 current proved undeveloped locations are based on approximate 55-acre well spacing and 44 of these locations are more than one location away from a current producer.

Technology Used to Establish Proved Reserves

We are employing technologies that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps, seismic data, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques. Geologic data from well logs, core analysis and seismic data in the Eagle Ford area is used to assess reservoir continuity more than one location away from production.

Internal Control

The preparation of our reserve estimates is in accordance with our prescribed internal control procedures that include verification of input data into a reserve forecasting and economic software, as well as management review. Internal controls include but are not limited to the following:

- The review of internal reserve estimates by well and by area by the Corporate Engineering Manager. A variance by well to the previous year-end reserve report and quarter-end reserve estimate is used as a tool in this process.

- The discussion of any material reserve variances among the internal reservoir engineers and the Corporate Engineering Manager to ensure the best estimate of remaining reserves.

- The review of internal reserve estimates by senior management and the Audit Committee of our Board of Directors prior to publication.

The Company s primary reserves estimator is Mark D. Petrichuk, Corporate Engineering Manager. Mr. Petrichuk has 35 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and natural gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Corporate Engineering Manager maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to the independent third party engineers for the annual audit of our year-end reserves.

Qualifications of Third Party Engineers

The reserves estimates shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional

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Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit incorporated herein are Mr. Danny Simmons and Mr. David Nice. Mr. Simmons has been a practicing consulting petroleum engineer at NSAI since 1976. Mr. Simmons is a Registered Professional Engineer in the State of Texas (License No. 45270) and has more than 35 years of practical experience in petroleum engineering, with over 35 years of experience in the estimation and evaluation of reserves. He graduated from the University of Tennessee in 1973 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Nice has been a practicing consulting petroleum geologist at NSAI since 1998. Mr. Nice is a Certified Petroleum Geologist and Geophysicist in the State of Texas (License No. 346) and has over 27 years of practical experience in petroleum geosciences, with over 14 years of experience in the estimation and evaluation of reserves. He graduated from the University of Wyoming in 1982 with a Bachelor of Science Degree in Geology and in 1985 with a Master of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Capital Expenditures

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2012, 2011, and 2010:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Capital expenditures	$ 613,343	$ 452,304	$ 268,578
Leasehold	18,753	10,605	49,328
Acquisitions			5,986
Delay rentals	1,089	1,144	1,193
Geological and geophysical/seismic	1,269	2,638	518
Exploration overhead	6,041	7,049	7,775
Capitalized interest	3,757	5,511	4,017
Other corporate	8,731	296	2,042
Total capital expenditures	$ 652,983	$ 479,547	$ 339,437

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2012. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing oil, NGLs and natural gas.

	Undeveloped Acres		Developed Acres		Productive Wells (2)			
					Gross		Net	
	Gross	Net	Gross	Net	Oil	Natural Gas	Oil	Natural Gas
Eagle Ford	51,003	49,618	56,121	17,319	17	115	16	104
South Texas			5,307	5,307		25		25
Other (1)	186,859	160,812	14,887	7,025	1	13		
Total	237,862	210,430	76,315	29,651	18	153	16	129

(1) Other primarily includes acreage in the Rockies area in which we still hold interests as well as acreage related to our new venture opportunities outside of the Eagle Ford area. Other excludes approximately

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228,000 net undeveloped acres under exploration option in the Southern Alberta Basin which will expire in January 2014.

(2) Of our productive wells listed above, there were no multiple completions.

The following table shows our interest in undeveloped acreage as of December 31, 2012 that is subject to expiration in 2013, 2014, and 2015 and thereafter, to the extent that we do not commence or continue drilling operations upon such acreage:

2013		2014		2015		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
8,963	7,671	25,807	10,228	70,894	54,930	132,198	84,002

Drilling Activity

The following table sets forth the number of gross exploratory and gross development wells we drilled or in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells completed at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of production.

	Gross Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2012	6.0		6.0	79.0		79.0
2011	5.0		5.0	59.0		59.0
2010	10.0		10.0	115.0	2.0	117.0

The following table sets forth the number of net exploratory and net development wells we drilled based on our proportionate working interest in such wells during the last three fiscal years.

	Net Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2012	6.0		6.0	75.7		75.7
2011	5.0		5.0	47.9		47.9
2010	9.9		9.9	112.4	2.0	114.4

At December 31, 2012, we had 38 gross and 36 net wells that were in the process of being drilled or waiting on results from completion. Of these wells, 36 were located in the Eagle Ford area where we own a 90% working interest in 20 wells and a 100% working interest in the remaining 16 wells. Two gross and two net additional exploratory wells in which we own 100% of the working interests were in the process of being drilled at December 31, 2012.

Marketing

We market the oil, NGL and natural gas production from properties we operate for both our account and the accounts of the other working interest owners in our properties. We sell our production to a variety of purchasers under purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. Our oil production is sold to third parties who collect the oil at the wellhead, on the lease, at our truck loading terminal or at a truck loading terminal we have contracted with to gather, stabilize and deliver to downstream pipelines or load oil onto purchasers trucks. We sell most of our oil production under contracts priced on the daily settlement price of the New York Mercantile Exchange (NYMEX), prompt month contract for West Texas Intermediate or regional oil postings. All prices are adjusted for location, quality, gravity and transportation differentials. Our natural gas is transported and sold under contract at a negotiated price, the majority of which is based on the Houston Ship Channel index, adjusted for transportation or market conditions. Our NGLs that are extracted from

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the natural gas during processing are purchased by the processors and priced based on the average daily price of NGLs at Mont Belvieu.

Major Customers

In 2012, four customers, Enterprise Products Operating LLC, Shell Trading (US) Company, Exxon Mobil Corporation and Calpine Energy Services, accounted for approximately 21%, 21%, 13% and 12%, respectively, of our consolidated revenue, excluding the effects of derivative instruments. The loss of any one of these customers would not have a material adverse effect on our operations as management believes other purchasers are available in our areas of operations.

In 2011, four customers, Shell Trading (US) Company, Calpine Energy Services, Regency Gas Services, LLC, and Exxon Mobil Corporation, accounted for approximately 25%, 24%, 17% and 10%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

In 2010, two customers, Calpine Energy Services and Shell Trading (US) Company, accounted for approximately 48% and 16%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources than we do. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resulting products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, securing sufficient capacity from processing and/or refining facilities for our NGL production, and obtaining purchasers and transporters of the oil, NGLs and natural gas we produce. There is also competition between producers of oil, NGLs and natural gas and other companies producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such legislation and regulations may, however, substantially increase the costs of exploring for, developing, producing or marketing oil, NGLs and natural gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Seasonal Nature of Business

Generally, the demand for oil, NGLs and natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel.

Government Regulation

The oil and natural gas industry is subject to extensive laws that are subject to change. These laws have a significant impact on oil and natural gas exploration, production and marketing activities and increase the cost of doing business, and consequently, affect profitability. Some of the legislation and regulation affecting the oil and natural gas industry carry significant penalties for failure to comply and could result in a shut-down of operations. While there can be no assurance that we will not incur fines, penalties or other sanctions, we believe we are currently in material compliance with the applicable federal, state and local laws. Because enactment of new laws

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affecting the oil and natural gas industry is common and because existing laws are often amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil and natural gas company operating in the U.S. The following are significant types of legislation affecting our business.

Exploration and Production Regulation

Oil, NGL and natural gas production is regulated under a wide range of federal, state and local statutes, rules, orders and regulations, including laws related to the location, drilling and casing of wells; well production limitations; spill prevention plans; surface use and restoration; platform, facility and equipment removal; the calculation and disbursement of royalties; the plugging and abandonment of wells; bonding; permits for drilling operations; and production, severance and ad valorem taxes. Oil and natural gas companies can encounter delays in drilling from the permitting process and requirements. Our operations are subject to regulations governing operation restrictions and conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and prevention of flaring or venting of natural gas. The conservation laws have the effect of limiting the amount of oil, NGLs and natural gas we can produce from our wells and limit the number of wells or the locations at which we can drill.

Environmental Regulation

Our operations are subject to extensive environmental, health and safety regulation by federal, state and local agencies. These requirements govern the handling, generation, storage and management of hazardous substances, including how these substances are released or discharged into the air, water, surface and subsurface. These laws and regulations often require permits and approvals from various agencies before we can commence or modify our operations or facilities and on occasion (especially on federally-managed land) require the preparation of an environmental impact assessment or study (which can result in the imposition of various conditions and mitigation measures) prior to or in connection with obtaining such permits. In connection with releases of hydrocarbons or hazardous substances into the environment, we may be responsible for the costs of remediation even if we did not cause the release or were not otherwise at fault, under applicable laws. These costs can be substantial and we evaluate them regularly as part of our environmental and asset retirement programs. Failure to comply with applicable laws, permits or regulations can result in project or operational delays, civil or in some cases criminal fines and penalties and remedial obligations.

Climate Change. Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for some of our produced materials. Such initiatives may contain a cap and trade approach to greenhouse gas regulation, which would require companies to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances declines, the cost would presumably increase. While the current prospect for such climate change legislation by the current U.S. Congress appears to be low, several states have adopted, or are in the process of adopting greenhouse gas reporting or cap-and-trade programs. Therefore, while the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), we would expect our operating costs to increase as we buy additional allowances or embark on emission reduction programs.

Even without further federal legislation, the U.S. Environmental Protection Agency (EPA) has begun to regulate greenhouse gas emissions. In 2009 and 2010, the EPA promulgated new greenhouse gas reporting rules, requiring certain petroleum and natural gas facilities and facilities that emit more than 25,000 tons per year of carbon dioxide equivalents (CO_2e) to prepare and file annual emission reports. These rules, which are currently in effect and to which some of our facilities are subject, may require some data reporting in 2013 for our facilities if they emitted more than 25,000 tons of CO_2e in 2012, with annual reporting thereafter. Our emissions in 2011

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were below the 25,000 tons of CO_2e threshold and we were not required to report our greenhouse gas emissions to EPA in 2012. In addition, on May 13, 2010, the EPA issued a new tailoring rule, which imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of CO_2e. This rule does not currently affect our operations but may as our operations grow. As a result of these regulatory initiatives, our operating costs may increase due to compliance with these programs, although we are not situated differently in this respect from our competitors in the industry.

Ground Water Impact due to Hydraulic Fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act (SDWA) to subject hydraulic fracturing operations to regulation under the SDWA s Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against us. In addition, the federal government is currently undertaking several studies of hydraulic fracturing s potential impacts. The Secretary of Energy Advisory Board published their ninety-day report that included a number of recommendations. On December 21, 2012, the EPA published an update on its ongoing national study currently underway to better understand any potential impacts of hydraulic fracturing on drinking water resources. A report that compiles the results of various research projects is expected during 2014. The EPA has developed draft permitting guidance under the SDWA where the EPA is the permitting authority for hydraulic fracturing activities that use diesel fuels in fracturing fluids. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate waste water discharges from hydraulic fracturing and other natural gas production. Further, on May 11, 2012, the Bureau of Land Management issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. While we are in material compliance with applicable environmental laws and regulations and do not use diesel fuels as one of our hydraulic fracturing fluid components, the increased legislation, regulation or enforcement of hydraulic fracturing operations at the federal level could lead to operational delays, increased operating costs and additional regulatory burdens for our business.

Furthermore, a number of states, local governments and regulatory commissions have adopted, or are evaluating the adoption of, legislation or regulations that could impose more stringent permitting, disclosure, well construction, water usage and wastewater disposal requirements on hydraulic fracturing operations. Because we already participate in public disclosure on the FracFocus.com internet site, we do not anticipate experiencing a material adverse effect from disclosure requirements. The outcome for other proposed state, regional and local regulations is uncertain, but potential increased legislation, regulation or enforcement of hydraulic fracturing at the state, regional or local level could reduce our drilling activity or increase our operating costs.

Air Emissions from Oil and Natural Gas Operations. On August 16, 2012 the EPA published final rules that extend New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) to certain exploration and production operations. The first compliance date was October 15, 2012 with a phase-in of some of the requirements over the next two years. The final rule requires the use of reduced emission completions or green completions on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Only a portion of these new rules appear to affect our operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase our operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase our operating and capital expenditures, we do not currently expect such existing and new regulations will have a material adverse impact on our operations or financial results.

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Derivative Legislation

The Dodd-Frank Act establishes federal oversight and regulation of the over-the-counter derivatives market. The legislation was signed into law in 2010 and requires the Commodities Futures Trading Commission (the CFTC), the SEC and other regulators to promulgate regulations implementing the new legislation. Among other things, the Dodd-Frank Act and the regulations promulgated under the Dodd-Frank Act impose requirements relating to reporting and recordkeeping, position limits, margin and capital, and mandatory trading and clearing. While certain regulations are already in effect, the implementation process is still ongoing, and we cannot yet predict the ultimate effect of the regulations on our business. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties.

Insurance Matters

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is unavailable or because premium costs are considered prohibitive. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows. We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law.

Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil and natural gas reserves with the U.S. Department of Energy (DOE) for those properties which we operate. During 2012, we filed estimates of our oil, NGL and natural gas reserves as of December 31, 2011 with the DOE, which differed by five percent or less from the reserve data presented in the Annual Report on Form 10-K for the year ended December 31, 2011. For information concerning proved reserves, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Employees

As of February 8, 2013, we had 183 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines, as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Available Information

Through our website, *http://www.rosettaresources.com,* you can access, free of charge, our filings with the SEC, including 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, as amended, our proxy statements, our Code of Business Conduct and Ethics, Nominating and Corporate Governance Committee Charter, Audit Committee Charter, and Compensation Committee Charter. You may also read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website can be accessed at *http://www.sec.gov*.

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Item 1A. Risk Factors

Oil, NGL and natural gas prices are volatile, and a decline in these prices would significantly affect our financial results and impede our growth. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

Our revenue, profitability and cash flow depend substantially upon the prices of and demand for oil, NGLs and natural gas. The markets for these commodities are volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil, NGLs and natural gas fluctuate widely in response to a variety of factors beyond our control, such as:

- domestic and foreign supply of oil, NGLs and natural gas;
- price and quantity of foreign imports of oil, NGLs and natural gas;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- restrictions on exportation of our oil, NGLs and natural gas;
- consumer demand;
- the impact of energy conservation efforts;
- regional price differentials and quality differentials of oil, NGLs and natural gas;
- domestic and foreign governmental regulations, actions and taxes;
- political conditions in or affecting other oil producing and natural gas producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the availability of refining capacity;
- weather conditions and natural disasters;
- technological advances affecting oil, NGL and natural gas production and consumption;

- overall U.S. and global economic conditions;
- price and availability of alternative fuels;
- seasonal variations in oil, NGL and natural gas prices;
- variations in levels of production; and
- the completion of large domestic or international exploration and production projects.

Further, oil, NGL and natural gas prices do not necessarily fluctuate in direct relation to each other. Our revenue, profitability, and cash flow depend upon the prices of, supply and demand for oil, NGLs and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices may:

- negatively impact the value of our reserves, because declines in oil, NGL and natural gas prices would reduce the value and amount of oil, NGLs and natural gas that we can produce economically;
- reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and
- result in a decrease in the borrowing base under our Credit Facility or otherwise limit our ability to borrow money or raise additional capital.

Adverse economic and capital market conditions may significantly affect our ability to meet liquidity needs, access to capital and cost of capital.

During the last few years, concerns over inflation, the stability of sovereign debt levels, volatility and declines in the prices of securities and the bankruptcy, failure, collapse or sale of financial institutions have led to

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diminished expectations of the U.S. and foreign economies. These factors, combined with increased levels of unemployment and diminished liquidity and credit availability, prompted an unprecedented level of intervention by the U.S. federal government and other governments.

If the economic recovery in the U.S. or other large economies is slow or prolonged, our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital. In addition, volatility and disruption in the financial and credit markets may adversely affect the financial condition of lenders in our Credit Facility and/or the ability or willingness of other lenders to participate in our Credit Facility. These market conditions may adversely affect our liquidity by limiting our ability to access our Credit Facility.

Potential deterioration in the credit markets, combined with a decline in commodity prices, may impact our capital expenditure level and also our counterparty risk.

While we seek to fund our capital expenditures primarily through cash flows from operating activities, we have in the past also drawn on unused capacity under our Credit Facility for capital expenditures. Borrowings under our Credit Facility are subject to the maintenance of a borrowing base, which is subject to semi-annual review and other adjustments. In the event that our borrowing base is reduced, outstanding borrowings in excess of the revised borrowing base will be due and payable immediately and we may not have the financial resources to make the mandatory prepayments. If our ability to borrow under our Credit Facility is impacted, we may be required to reduce our capital expenditures, which may in turn adversely affect our ability to carry out our business plan. Furthermore, if we lack the resources to dedicate sufficient capital expenditures to our existing oil and natural gas leases, we may be unable to produce adequate quantities of oil and natural gas to retain these leases and they may expire due to a lack of production. The loss of leases could have a material adverse effect on our results of operations.

Development and exploration drilling activities do not ensure reserve replacement and thus our ability to generate revenue.

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Our future oil, NGL and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline dependent on reservoir characteristics. Our total proved reserves decline as reserves are produced. Our ability to make the necessary capital investment to maintain or expand our asset base of oil, NGL and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

The terms of our agreements governing our indebtedness contain a number of operating and financial covenants. If we are unable to comply with these covenants, the repayment of our indebtedness may be accelerated.

We are subject to a number of covenants in our Credit Facility and in the indenture governing our Senior Notes that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, make capital expenditures, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, enter into sale and leaseback transactions and pay dividends on our common stock. We are also required by the terms of our Credit Facility to comply with financial covenants. A more detailed description of our Credit Facility and the indenture governing our Senior Notes is included in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and the footnotes to the audited Consolidated Financial Statements included elsewhere in this Form 10-K.

A breach of any of the covenants imposed on us by the agreements governing our indebtedness, including the financial covenants in our Credit Facility, could result in a default under such indebtedness. In the event of a default, the lenders under our Credit Facility could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facilities, which is substantially all of our assets. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

Our exploration and development activities may not be commercially successful.

Exploration and development activities involve numerous risks, including the risk that no commercially productive quantities of oil, NGLs and natural gas will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- reductions in oil, NGL and natural gas prices;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- disruptions to production from producing wells related to hydraulic fracturing operations in nearby wells;
- interference between producing wells, as a result of, among other things, spacing between wells;
- equipment failures, including corrosion of aging equipment, systems failures and extended downtime, or accidents;
- unavailability or high cost of drilling rigs, equipment or labor;
- lost or damaged oilfield development and services tools;
- limitations in midstream infrastructure or the lack of markets for oil, NGLs and natural gas;
- unavailability or high cost of processing and transportation;
- human error;
- community unrest;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers;

adverse weather conditions, including severe droughts resulting in new restrictions on water usage;

environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;

compliance with environmental and other governmental regulations;

possible federal, state, regional and municipal regulatory moratoriums on new permits, delays in securing new permits, changes to existing permitting requirements without grandfathering of existing permits and possible prohibition and limitations with regard to certain completion activities; and

increases in severance taxes.

Our decisions to purchase, explore, develop and exploit prospects or properties depend, in part, on data obtained through geological and geophysical analyses, production data and engineering studies, the results of which are uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying potentially productive hydrocarbon traps and geohazards. They do not allow the interpreter to know conclusively if hydrocarbons are present or economic. In addition, the use of 3-D

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seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future financial position, results of operations and cash flows.

Numerous uncertainties are inherent in our estimates of oil, NGL and natural gas reserves and our estimated reserve quantities, and our present value calculations may not be accurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the estimated quantities and present value of our reserves.

Estimates of proved oil, NGL and natural gas reserves and the future net cash flows attributable to those reserves are prepared by our engineers and audited by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil, NGL and natural gas reserves and cash flows attributable to such reserves, including factors beyond our engineers control. Reserve engineering is a subjective process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil, NGL and natural gas prices, expenditures for future development and exploration activities, engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions based upon production history, development and exploration activities and prices of oil, NGLs and natural gas. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The present value of future net revenues from our proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil, NGL and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on an average price, calculated as the twelve-month first-day-of-the month historical average price for the twelve-month period prior to the end of the reporting period, and costs as of the date of the estimate. Our reserves as of December 31, 2012 were based on the trailing twelve-month first-day-of-the-month historical unweighted averages of West Texas Intermediate oil prices, adjusted for basis and quality differentials, of $91.21 per Bbl and Henry Hub natural gas prices, adjusted for basis and quality differentials, of $2.76 per MMBtu. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the standardized measure of future net cash flows for reporting purposes in accordance with the SEC s rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry, in general, will affect the appropriateness of the 10% discount factor in arriving at the standardized measure of future net cash flows.

Downward revisions of reserves or lower oil and natural gas prices could result in impairments of our oil and natural gas properties.

Under the full cost method, we are subject to quarterly calculations of a ceiling, or limitation, on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, a write-down would reduce earnings and impact stockholders equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgment. The current ceiling calculation utilizes a trailing twelve-month first-day-of-the-month historical unweighted average price and does not allow us to re-evaluate the calculation subsequent to the end of the period if prices increase. It also dictates that costs in effect as of the last day of the quarter are held constant. The risk that we will be required to write down the carrying

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value of oil and natural gas properties increases when oil and natural gas prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. It is possible that we may recognize revisions to our proved reserves in the future. Write-downs recorded in one period will not be reversed in a subsequent period even though higher oil and natural gas prices may have increased the ceiling applicable in the subsequent period.

We have not recorded any write-downs or impairments for the years ended December 31, 2012, 2011 or 2010. Due to the volatility of commodity prices, however, should oil and natural gas prices decline in the future, it is possible that write-downs could occur. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates for further information.

Changes in governmental laws, regulations, and rules could materially affect our business, results of operations, cash flows, financial position and future growth.

Our activities are subject to federal, state, regional and local laws and regulations. Some of the laws, regulations and rules contain provisions for significant fines and penalties for non-compliance. Changes in laws and regulations could affect our costs of operations, production levels, royalty obligations, price levels, environmental requirements, and other aspects of our business, including our general profitability. We are unable to predict changes to existing laws and regulations. For example, the EPA has recently focused on public concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities. On August 16, 2012, the EPA published final rules that extend New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) to certain exploration and production operations. This renewed focus could lead to additional federal and state regulations affecting the oil and natural gas industry. New regulations or changes to existing laws and regulations could materially affect our business, results of operations, cash flows, financial position and future growth.

Our business requires a staff with technical expertise, specialized knowledge and training and a high degree of management experience.

Our success is largely dependent upon our ability to attract and retain personnel with the skills and experience required for our business. An inability to sufficiently staff our operations or the loss of the services of one or more members of our senior management or of numerous employees with technical skills could have a negative effect on our business, financial position, results of operations, cash flows and future growth.

Market conditions or transportation impediments may hinder our access to oil, NGL and natural gas markets or delay our production.

Market conditions, the unavailability of satisfactory oil, NGL and natural gas processing and transportation to available markets or the remote location of certain of our drilling operations may hinder our access to markets or delay our production. The availability of a ready market for our various products depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines, terminals and trucking, railroad and/or barge transportation and processing facilities. Our ability to market our production also depends in substantial part on the availability and capacity of gathering systems, pipelines, terminals, other means of transportation and processing facilities. We may be required to shut in wells or delay production for lack of a market or because of inadequacy or unavailability of gathering systems, pipelines, or other means of transportation or processing facilities. The transportation of our production may be interrupted under the terms of our interruptible or short-term transportation agreements due to capacity constraints on the applicable system. The transportation of our production may also be interrupted under the terms of our firm long-term transportation, terminal and processing agreements due to operational upset, third party force majeure or other events beyond our control. Further, any disruption of third-party facilities due to maintenance, repairs, debottlenecking, expansion projects, weather or other interruptions of service could negatively impact our ability to market and deliver our products. Our concentration of operations in the Eagle

Ford area increases these risks and their potential impact upon us. If we experience any interruptions to the transportation and/or processing of our products, we may be unable to realize revenue from our wells until our production can be tied to a pipeline or gathering system, transported by truck, rail and/or barge, or processed, as applicable, into the particular products. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil, NGLs and natural gas and ultimate realization of revenues.

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil, NGLs and natural gas and securing equipment and trained personnel. Our competitors include major and large independent oil and natural gas companies that possess financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties at a lower cost and more quickly than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our strategy as an onshore unconventional resource player has resulted in operations concentrated in one geographic area and increases our exposure to many of the risks enumerated herein.

Currently our operations are highly concentrated in the Eagle Ford area. As our largest producing area, this play provided approximately 98% of our total revenue for 2012, excluding the impact of derivative instruments, and represents nearly 100% of our estimated total proved reserves as of December 31, 2012. This concentration increases the potential impact that many of the risks stated herein may have upon our ability to perform. For example, we have greater exposure to regulatory actions impacting Texas, natural disasters in the geographic area, competition for equipment, services and materials available in the area and access to infrastructure and markets.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. If the level of exploration and production increases in the future, the demand for and costs of oilfield services could rise, while the quality of these services may decline. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in the Eagle Ford area, we could be materially and adversely affected because our operations and properties are concentrated in this area.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and natural gas business involves certain operating hazards such as:

- well blowouts;
- cratering;

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- explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- hurricanes, tropical storms and flooding;
- pollution;
- releases of toxic gas; and
- surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition or could result in a loss of our properties. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, our insurance policies provide limited coverage for losses or liabilities relating to sudden and accidental pollution, but not for other types of pollution. Our insurance might be inadequate to cover our liabilities. Our energy package is written on reasonably standard terms and conditions that are generally available to the exploration and production industry. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs could increase in the future as the insurance industry adjusts to difficult exposures and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur a liability for a risk at a time when we do not have liability insurance, then our business, financial position, results of operations and cash flows could be materially adversely affected.

Our current insurance policies provide some coverage for losses arising out of our hydraulic fracturing operations. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up activities, and total losses related to a spill, contamination or blowout during completion operations could exceed our per occurrence or aggregate policy limits. Furthermore, our current insurance policies do not provide coverage for ground water contamination due to any migration if not discoverable within a certain period, from fractured areas or from leaking associated with inadequate casing or cementing or defective and/or inadequate pipe and/or casing in the vertical sections of any of our shale wells that traverse aquifers in the locations of our producing properties. Any losses due to hydraulic fracturing that are not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Regulation and competition of hydraulic fracturing services could impede our ability to develop our shale plays.

Hydraulic fracturing activities are required for all of our wells on our shale producing properties. Our shale properties are dependent on our ability to hydraulically fracture the producing formations. Commonly referred to as fracking, hydraulic fracturing is an integral part of the well completion process for all of our shale properties, including all of our exploration and development activities related to these properties.

The fracking process involves pumping fluid at high pressure into underground shale formations through steel pipe that is perforated at the location of the hydrocarbons. The composition of the fluid is generally 99% water and sand or a ceramic material called proppant and less than 1% of highly diluted chemical additives, many of which are commonly found in household items. The high pressure creates small fractures that allow the oil and natural gas to flow into the well bore for collection at the surface. While the majority of the proppant remains wedged underground to prop open the fractures, a percentage of the water and additives flows back from

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hydraulic fracturing operations. These fluids are then either recycled onsite or must be transported to and disposed of at sites that are approved and permitted by applicable regulatory authorities.

The practice of hydraulic fracturing formations to stimulate production of oil and natural gas has come under increased scrutiny by the environmental community. Various federal, state and local initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing. For example, in 2011, Texas has adopted regulations requiring certain hydraulic fracturing disclosures. Although hydraulic fracturing has been largely exempt from the federal Safe Drinking Water Act since 2005, bills have been considered in Congress that would repeal this exemption. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. For example, the EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2014. Further, on May 11, 2012, the Bureau of Land Management (BLM) issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. The Department of the Interior announced on January 18, 2013 that the BLM will issue a revised draft rule by March 31, 2013. The adoption of any future federal, state or local laws or regulations imposing additional permitting, disclosure or regulatory obligations related to, or otherwise restricting or increasing costs regarding the use of, hydraulic fracturing could make it more difficult to conduct drilling activity. As a result, such additional regulations could affect the volume of hydrocarbons we recover, and could increase the cycle times and costs to receive permits, delay or possibly preclude receipt of permits in certain areas, impact water usage and waste water disposal and require air emissions, water usage and chemical additives disclosures.

Although it is not possible at this time to predict the final outcome of the proposed legislation and regulations regarding hydraulic fracturing, any new restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions and, if the use of hydraulic fracturing is limited or prohibited, could lead to our inability to access existing and new oil, NGL and natural gas reserves in the future.

Our industry is experiencing a growing emphasis on the exploitation and development of shale resource plays which are dependent on hydraulic fracturing for economically successful development. We engage third-party contractors to provide hydraulic fracturing services and related services, equipment and supplies. The availability or high cost of high pressure pumping services (or hydraulic fracturing services), chemicals, proppant, water, and related services and equipment could limit our ability to execute our exploration and development plans on a timely basis and within our budget. Hydraulic fracturing in shale plays requires high pressure pumping service crews. A shortage of service crews or proppant, chemicals or water could materially and adversely affect our operations and the timeliness of executing our development plans within our budget.

Hydraulic fracturing operations can result in air emissions, surface spillage and surface or ground water contamination, or ground water contamination by reason of well design and/or construction, and a blowout during completion operations when hydraulic services are being provided could result in personal injury or death and loss or damage to property. Additionally, pre-existing or concurrent non-Company spillage, contamination or property damage could result in litigation, government fines and penalties or remediation or restoration obligations, and damages.

Environmental matters and costs can be significant.

The oil and natural gas business is subject to various federal, state, and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Such laws and regulations may impose liability on us for pollution clean-up, remediation, restoration and other liabilities arising from or related to our operations. Any noncompliance with these laws and regulations could subject us to material administrative, civil

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or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production. We also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. The cost of future compliance is uncertain and is subject to various factors, including future changes to laws and regulations. We have no assurance that future changes in or additions to the environmental laws and regulations will not have a significant impact on our business, results of operations, cash flows, financial condition and future growth.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil, NGLs and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to the warming of the Earth s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. In recent years, the U.S. Congress has considered climate-related legislation to reduce emissions of greenhouse gases. In addition, at least 20 states have developed measures to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The EPA has adopted regulations requiring reporting of greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as air pollutants under the existing federal Clean Air Act. In November 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules required data collection beginning in 2011 and reporting beginning in 2012, with annual reporting thereafter if emissions exceed 25,000 tons per year of CO_2e. Although our emissions did not exceed this threshold in 2011 and our 2012 emissions data collection is in progress, some of our facilities may be subject to these rules in the future. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of other regulations by the EPA or analogous state agencies, that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect on our operations and the demand for oil and natural gas.

Our property acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make property acquisitions and/or realize anticipated benefits of those acquisitions.

Our growth strategy includes acquiring oil and natural gas properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

- diversion of management s attention;
- ability or impediments to conducting thorough due diligence activities;
- potential lack of operating experience in the geographic market where the acquired properties are located;
- an increase in our expenses and working capital requirements;
- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs, including synergies;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity under our Credit Facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;

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- the incurrence of other significant charges, such as impairment of oil and natural gas properties, asset devaluation or restructuring charges; and

- the inability to transition and integrate successfully or timely the businesses and/or assets we acquire.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, environmental compliance review and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully access their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Derivative transactions may limit our potential revenue or result in financial losses which would reduce our income.

We have entered into oil, NGL and natural gas price derivative contracts with respect to a portion of our expected production through 2015. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to rise over the price established by the contract. Such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative contract, or the counterparties to our derivative contracts fail to perform under the contracts. Our current derivative instruments are with counterparties that are lenders under our Credit Facility or were lenders under our Credit Facility upon origination of the derivative instrument. A default by any of our counterparties could negatively impact our financial performance.

The adoption of the Dodd-Frank Act could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business, resulting in our operations becoming more volatile and our cash flows less predictable.

Congress has adopted the Dodd-Frank Act, a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market. The legislation was signed into law by President Obama in 2010 and requires the CFTC, the SEC and other regulators to promulgate regulations implementing the new legislation. While certain regulations are already in effect, the implementation process is still ongoing, and we cannot yet predict the ultimate effect of the regulations on our business.

The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an ongoing basis, to identify any potential change in our regulatory status.

Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for non-compliance. Certain CFTC recordkeeping and reporting requirements are already effective, and additional recordkeeping and reporting requirements will be phased in through April 2013. These additional recordkeeping and reporting requirements may require additional compliance resources and may also have a negative effect on market liquidity, which could negatively impact commodity prices and our ability to hedge our commercial price risk.

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The CFTC has also issued regulations to set position limits for certain futures, options, and swap contracts in the major energy markets. A United States District Court recently vacated and remanded the position limits rules to the CFTC. The CFTC has appealed that ruling and it is uncertain at this time whether, when, and to what extent the CFTC s position limits rules will become effective.

The new regulations may also require us to comply with certain margin requirements for our over-the-counter derivative contracts with certain regulated entities, which could adversely affect our liquidity and ability to use derivatives to hedge our risks; however, the proposed margin rules are not yet final and therefore the application of those provisions to us is uncertain at this time. The financial reform legislation may also require our counterparties to spin off some of their derivatives activities to a separate entity, which entity may not be as creditworthy as the current counterparty.

The new legislation also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform, which may result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from our Board of Directors and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for our commercial hedging program.

Rules promulgated under the Dodd-Frank Act further defined forward contracts as well as instances where forwards may become swaps. Because guidance regarding forwards is still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall within the regulatory category of swaps. In addition, the CFTC s rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

The impairment of financial institutions or counterparty credit default could adversely affect us.

Our commodity derivative transactions expose us to credit risk in the event of default by our counterparties. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. In addition, if any lender under our Credit Facility is unable to fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender s commitment under our Credit Facility. Currently, no single lender in our Credit Facility has commitments representing more than 12% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

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Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in the President s Fiscal Year 2013 budget proposal, released by the White House on February 13, 2012, is the elimination of certain U.S. federal income tax deductions and credits currently available to oil and natural gas exploration and production companies. Such proposed changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered, and in some cases proposed, similar changes to the existing federal income tax laws that affect oil and natural gas exploration and production companies. It is unclear, however, whether any such changes will be enacted or, if enacted, how soon such changes would be effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, we do not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

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

Trading Market

Our common stock is listed on The NASDAQ Global Select Market® under the symbol ROSE . The following table sets forth the high and low sale prices of our common stock for the periods indicated:

2012	High	Low	2011	High	Low
January 1 - March 31	$ 54.43	$ 43.59	January 1 - March 31	$ 49.55	$ 33.30
April 1 - June 30	51.35	32.37	April 1 - June 30	53.87	37.64
July 1 - September 30	49.96	35.68	July 1 - September 30	58.04	34.03
October 1 - December 31	51.78	41.65	October 1 - December 31	54.58	30.42

The number of shareholders of record on February 8, 2013 was approximately 185. However, we believe that we have a significantly greater number of beneficial shareholders since a substantial number of our common shares are held of record by brokers or dealers for the benefit of their customers.

We have not paid a cash dividend on our common stock and currently intend to retain earnings to fund the growth and development of our business. Any future change in our policy will be made at the discretion of our board of directors in light of our financial condition, capital requirements, earnings prospects and limitations imposed by our lenders or by any of our investors, as well as other factors the board of directors may deem relevant. The declaration and payment of dividends is restricted by our Credit Facility and the indenture governing our 9.500% Senior Notes due 2018 (Senior Notes). Future agreements may also restrict our ability to pay dividends.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2012:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs
October 1- October 31	754	$ 47.74		
November 1 - November 30	1,836	47.38		
December 1 - December 31	279	44.69		
Total	2,869	$ 47.21		

(1) All of the shares were surrendered by our employees and certain of our directors to pay tax withholding upon the vesting of restricted stock awards. We do not have a publicly announced program to repurchase shares of common stock.

Stock Performance Graph

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Securities Exchange Act, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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The following common stock performance graph shows the performance of our common stock up to December 31, 2012. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

- a $100 investment was made in our common stock at the closing trade price of $19.83 per share on December 31, 2007, and $100 was invested in each of the Standard & Poor s 500 Index (S&P 500) and the Standard & Poor s MidCap 400 Oil & Gas Exploration & Production Index (S&P 400 E&P) at the closing trade price on December 31, 2007; and

- all dividends are reinvested for each measurement period.

The S&P 400 E&P Index is widely recognized in our industry and includes a representative group of independent peer companies (weighted by market capital) that are engaged in comparable exploration, development and production operations.

Total Return Among Rosetta Resources Inc., the S&P 500 Index and the S&P 400 E&P Index

	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
ROSE	$ 100.00	$ 35.70	$ 100.45	$ 189.81	$ 219.36	$ 228.54
S&P 500	100.00	63.00	79.68	91.68	93.61	108.59
S&P 400 E&P	100.00	45.49	81.04	116.06	95.23	83.12

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Item 6. Selected Financial Data

The following selected financial data should be read in connection with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

	Year Ended December 31,				
	2012	2011	2010	2009 (1)	2008 (1)
	(In thousands, except per share data)				
Operating Data:					
Total revenues	$ 613,499	$ 446,200	$ 308,430	$ 293,951	$ 499,347
Net income (loss)	159,295	100,546	19,046	(219,176)	(188,110)
Net Income (loss) per share:					
Basic	$ 3.03	$ 1.93	$ 0.37	$ (4.30)	$ (3.71)
Diluted	3.01	1.91	0.37	(4.30)	(3.71)
Cash dividends declared and paid per common share:	$	$	$	$	$
Balance Sheet Data (At the end of the period):					
Total assets	$ 1,415,416	$ 1,065,345	$ 989,440	$ 872,042	$ 1,134,996
Long-term debt	410,000	230,000	350,000	288,742	300,000
Total other long-term liabilities	17,570	14,949	28,275	31,261	26,584
Stockholders equity	803,999	632,836	528,816	493,095	726,372

(1) Includes a $379.5 million and $444.4 million non-cash, pre-tax impairment charge for 2009 and 2008, respectively.

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

Overview

The following discussion addresses material changes in our results of operations for the year ended December 31, 2012 compared to the year ended December 31, 2011 and material changes in our financial condition since December 31, 2011.

Results for full-year 2012 include the following:

- production of 13.6 MMBoe compared to 10.1 MMBoe for the year ended December 31, 2011;

- 85 gross (82 net) wells drilled with a 100% success rate compared to 64 gross (53 net) wells drilled with a 100% success rate for the year ended December 31, 2011; and

- net income of $159 million, or $3.01 per diluted share, compared to $101 million, or $1.91 per diluted share, for the year ended December 31, 2011.

Our principal business strategy is focused on the acquisition, development and production of oil, NGLs and natural gas from unconventional resource plays. Our current assets are primarily located in the Eagle Ford area in South Texas, one of the most active plays in the U.S. In the last three years, we have become a significant producer in the liquids-rich window of the region and have established an inventory of lower-risk, higher-return drilling opportunities that offer more predictable and long-term production, reserve growth and a more valuable commodity mix. In addition to our focus in the Eagle Ford area, we are pursuing new opportunities to drive the long-term growth and sustainability of the Company. We continue to evaluate investments in other unconventional resource basins that offer a viable inventory of projects including new higher-risk exploration projects and producing property acquisitions. We believe we have the financial and operational flexibility to react quickly should such attractive opportunities that fit our profile be presented.

Our current operations in the Eagle Ford area are focused in four areas. Our original 2009 discovery is located in the 26,500-acre Gates Ranch leasehold in Webb County. We are also active in the Karnes Trough area,

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the Briscoe Ranch leasehold and in Central Dimmit County, where our positions were delineated in 2010 and 2011. Overall, as of December 31, 2012 we hold 67,000 net acres in the region with approximately 53,000 acres located in the crude oil and liquids producing portions of the play. We were an early entrant into the Eagle Ford area, accumulating most of our acreage positions during 2008 and 2009 when the trend was still in its infancy as an unconventional resource play.

The development of our assets in the Eagle Ford has led to substantial growth for the Company. During 2012, we recorded a 35% increase in daily production, with total liquids production growth of 76% and total proved reserves growth of 25% from 2011. As of December 31, 2012, our total estimated proved reserves were 201 MMBoe as compared to 161 MMBoe at the prior year-end. Of our total reserves, approximately 58% were liquids and 37% were classified as proved developed. Approximately 59% of our production during 2012 was attributable to crude oil and NGLs and 44% of our total liquids production was attributable to oil. This compares to 45% of our production being attributable to crude oil and NGLs and 41% of our total liquids production being attributable to oil in 2011. We replaced 472% of production from all sources at a reserve replacement cost of $10.03 per Boe.

We successfully drilled 85 gross wells and completed 64 gross wells during 2012. Of those wells, 80 were drilled and 62 were completed in the Eagle Ford area. As of December 31, 2012, we had completed a total of 126 gross wells in the Eagle Ford area. During 2012, we continued to record strong sequential growth in Eagle Ford volumes, averaging a record 44.2 MBoe/d in the fourth quarter, a 61% increase from the same period in 2011 and a 21% increase from the prior quarter. To handle the increased demand, we have secured multiple options for transportation and processing capacity with firm commitments in place to meet total planned production levels through 2014, and we have begun the process of securing additional firm capacity.

The development of our Eagle Ford assets combined with the sale of non-strategic assets continued to lower our overall cost structure as a company, with direct lease operating expenses for full-year 2012 decreasing to $2.42 per Boe from $2.72 per Boe for the same period in 2011. We also benefited from a decline in drilling and completion costs in the Eagle Ford area during the latter part of the year due to more favorable contractual terms that were the result of increased availability of services and materials and improvements in well completion design. Projected drilling and completion costs dropped in some areas by $1 million per well since our announcement of our 2013 capital program in December 2012.

With our shift to an unconventional resource strategy, we have streamlined our operations by divesting of assets that no longer fit our operating model. Since 2010, we have executed sale agreements for aggregate consideration of approximately $440 million. During 2012, we sold our Lobo assets and a portion of our Olmos properties in South Texas for $95 million, subject to customary closing adjustments, with a January 1, 2012 effective date.

During the second quarter of 2012, our exploratory drilling program in the Southern Alberta Basin in Northwest Montana was concluded. Of the seven horizontal wells that were drilled, five were completed. Based on results that were not economic, we have suspended all capital activity for exploration in the area. Our Southern Alberta Basin leases and lease options will begin to expire in January 2014.

Our 2013 capital program is expected to range from $640 million to $700 million, as compared to our original $700 million capital budget. We announced that approximately 10% of our capital program is budgeted for the evaluation of new venture opportunities inside as well as outside of the Eagle Ford area. Our 2013 announced capital program is based on an average five-rig program and includes the drilling of 75 wells along with the completion of 62 Eagle Ford wells. Approximately half of the completions will be located in the Gates Ranch area with the remainder in other areas in the liquids-rich window of the play, including the Karnes Trough area, Briscoe Ranch and Central Dimmit County. Since the announcement of our 2013 capital program, we have experienced reduced drilling and completion costs which we expect will provide greater flexibility in our 2013 capital expenditures.

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While our unconventional resource strategy is proving to be successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Although we cannot completely control all external factors that could affect our operating environment, our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. We have diversified our production base to include a greater mix of crude oil and NGLs, which continue to be priced at more favorable levels than natural gas. With our high concentration of production located in the Eagle Ford area, we have taken various steps to provide access to necessary services and infrastructure. We believe our 2013 capital program can be executed from internally-generated cash flow supplemented by borrowings under our Credit Facility. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs. If our internal funds are insufficient to meet projected funding requirements, we would consider curtailing capital spending or accessing the capital markets.

Availability under our Credit Facility is restricted to a borrowing base and committed amount, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on hedging arrangements and asset divestitures. The amount of the borrowing base and committed amount is dependent on a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. As of December 31, 2012, our borrowing base and committed amount under our Credit Facility was $625 million. As of February 25, 2013, we had $225 million of borrowings outstanding with $400 million available for borrowing.

Financial Highlights

Our consolidated financial statements reflect total revenue of $613.5 million based on total volumes of 13.6 MMBoe and derivative gains of $40.5 million for 2012.

Significant transactions which affect the comparability of our financial results between periods include the 2012 divestiture of our Lobo assets and a portion of our Olmos assets, the 2011 divestitures of our Sacramento Basin and DJ Basin assets and the 2010 divestitures of our Pinedale, San Juan, Arklatex, and Gulf Coast Sabine Lake assets.

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Results of Operations

The following table summarizes the components of our revenues for the periods indicated, as well as each period s production volumes and average realized prices:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except per unit amounts)		
Revenues:			
Oil sales	$ 318,782	$ 156,284	$ 54,542
NGL sales	160,461	125,301	45,200
Natural gas sales	93,711	163,382	208,688
Derivative instruments	40,545	1,233	
Total revenues	$ 613,499	$ 446,200	$ 308,430
Production:			
Oil (MBbls)	3,496.6	1,863.3	738.0
NGLs (MBbls)	4,471.9	2,643.3	1,096.0
Natural Gas (MMcf)	33,852.9	33,393.3	39,210.2
Total equivalents (MBoe)	13,610.6	10,072.1	8,369.0
Average sales price:			
Oil, excluding derivatives (per Bbl)	$ 91.17	$ 85.03	$ 73.91
Oil, including realized derivatives (per Bbl)	89.67	83.87	73.91
NGL, excluding derivatives (per Bbl)	35.88	51.26	41.24
NGL, including realized derivatives (per Bbl)	37.84	47.40	41.24
Natural gas, excluding derivatives (per Mcf)	2.77	4.00	4.50
Natural gas, including realized derivatives (per Mcf)	3.28	4.89	5.32
Revenue, excluding realized derivatives (per Boe)	42.10	42.45	32.98
Revenue, including realized derivatives (per Boe)	43.63	44.18	36.85

Revenue

Our revenue is derived from the sale of our oil, NGL and natural gas production, and includes the effects of our commodity derivative contracts. Our revenue may vary significantly from period to period as a result of changes in commodity prices, volumes of production sold and the impact of our commodity derivative instruments.

Excluding the effects of derivative instruments, revenue for 2012, 2011 and 2010 was $573.0 million, $427.5 million and $276.0 million, respectively, and year-over-year growth in 2012 and 2011 was attributable to increased oil and NGL production and higher average realized oil prices. Excluding the effects of derivative instruments, revenue attributable to oil and NGL sales in 2012, 2011 and 2010 was approximately 84%, 69% and 36%, respectively, of total revenue.

Oil sales. Oil revenue, excluding derivative instruments, of $318.8 million, $158.4 million and $54.5 million for 2012, 2011 and 2010, respectively, increased year-over-year due to higher oil production and higher realized prices. The increase in oil production was primarily attributable to our Gates Ranch and Klotzman wells in the Eagle Ford area, whose combined total oil production in 2012, 2011 and 2010 was 8.3 MBbls per day, 4.6 MBbls per day and 1.4 MBbls per day (Gates Ranch only), respectively.

For 2012, a realized derivative loss of $5.2 million is reported as a component of Derivative instruments within Revenues. For 2011, a realized derivative loss of $2.1 million is reported as a component of Oil sales within Revenues and reflects the effect of oil hedging activities on oil revenues. There was no effect of oil hedging activities on oil revenue for 2010 because no oil derivative transactions settled during the period.

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NGL sales. NGL revenue, excluding derivative instruments, of $160.5 million, $135.5 million and $45.2 million for 2012, 2011 and 2010, respectively, increased year-over-year. The increase in 2012 from 2011 was due to higher NGL production, partially offset by lower realized prices, and the increase in 2011 from 2010 was due to higher NGL production and higher realized prices. The increase in both periods due to higher NGL production was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total NGL production in 2012, 2011 and 2010 was 10.7 MBbls per day, 6.5 MBbls per day and 1.9 MBbls per day, respectively.

For 2012, a realized derivative gain of $8.7 million is reported as a component of Derivative instruments within Revenues. For 2011, a realized derivative loss of $10.2 million is reported as a component of NGL sales within Revenues and reflects the effect of NGL hedging activities on NGL revenues. There was no effect of NGL hedging activities on NGL revenue for 2010 because no NGL derivative transactions settled during the period.

Natural gas sales. Natural gas revenue, excluding derivative instruments, of $93.7 million, $133.6 million and $176.2 million for 2012, 2011 and 2010, respectively, decreased year-over-year. The decrease in 2012 from 2011 was due to lower realized prices, partially offset by higher natural gas production, and the decrease in 2011 from 2010 was due to lower realized prices and lower natural gas production. The increase in natural gas production of 1% in 2012 from 2011 was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total natural gas production in 2012, 2011 and 2010 was 77.8 MMcf per day, 56.0 MMcf per day and 15.9 MMcf per day, respectively. The decrease in natural gas production of 15% in 2011 from 2010 was primarily due to asset divestitures of our former gas-based assets, the suspension of drilling programs in areas that produce primarily from dry gas reservoirs and the natural decline of gas-based properties.

For 2012, a realized derivative gain of $17.4 million is reported as a component of Derivative instruments within Revenues. For 2011 and 2010, realized derivative gains of $29.8 million and $32.5 million are reported as components of Natural gas sales within Revenues and reflect the effect of natural gas hedging activities on natural gas revenues.

Derivative Instruments**.** In 2012, Derivative instruments include realized and unrealized derivative gains of $20.9 million and $19.6 million, respectively. Realized derivative gains represent cash settlements associated with our commodity derivative contracts, while unrealized derivative gains represent changes in fair value on commodity derivative contracts and the reclassification of commodity hedging gains from Accumulated other comprehensive income. In 2011, Derivative instruments included an unrealized derivative gain of $1.2 million associated with the change in fair value of our crude oil basis and NYMEX roll swaps. These instruments did not qualify for hedge accounting in 2011, the last year in which we elected hedge accounting, and the associated derivative gain has been reclassified from Oil sales to Derivative instruments to conform to our current year presentation.

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Operating Expenses

The following table summarizes our production costs and operating expenses for the periods indicated:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except per unit amounts)		
Direct lease operating expense	$ 32,874	$ 27,326	$ 37,816
Workover expense	1,279	594	2,196
Insurance expense	985	902	1,577
Ad valorem taxes	7,291	6,078	9,496
Lease operating expense	$ 42,429	$ 34,900	$ 51,085
Treating and transportation	51,826	22,316	6,963
Production taxes	16,722	12,073	5,953
Depreciation, depletion and amortization (DD&A)	154,223	123,244	116,558
General and administrative costs	68,731	75,256	56,332
Costs and expenses (per Boe of production)			
Direct lease operating expense	$ 2.42	$ 2.72	$ 4.52
Workover expense	0.09	0.06	0.26
Insurance expense	0.07	0.09	0.19
Ad valorem taxes	0.54	0.60	1.13
Lease operating expense	$ 3.12	$ 3.47	$ 6.10
Treating and transportation	3.81	2.22	0.83
Production taxes	1.23	1.20	0.71
Depreciation, depletion and amortization (DD&A)	11.33	12.24	13.93
General and administrative costs	5.05	7.47	6.73
General and administrative costs, excluding stock-based compensation	3.69	4.59	5.04
Production costs (1)	13.91	15.10	18.90

(1) Production costs per Boe include lease operating expense and DD&A and excludes ad valorem taxes.

Lease Operating Expense. Lease operating expense increased in 2012 from 2011 primarily due to our completion of 62 wells in the Eagle Ford area in 2012. As of December 31, 2012, we had completed a total of 126 gross Eagle Ford area wells. Lease operating expense decreased in 2011 primarily due to our 2011 divestitures of our Sacramento Basin assets in California and our DJ Basin assets in Colorado, as well as our overall lease operating expense reduction efforts.

Treating and Transportation. Treating and transportation expense increased year-over-year as a result of increased daily production of 67% and 236%, respectively, from 2011 and 2010 in the Eagle Ford area as well as higher unit costs required to transport incremental production from the area. In addition, we accrued deficiency fees of $5.2 million in 2012 related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during 2012.

Production Taxes. Production taxes are highly correlated to commodity revenues, production volumes and commodity prices, which have impacted this expense item. Production taxes as a percentage of oil and natural gas sales, excluding derivative instruments, were 4.1%, 4.1% and 2.6% for 2012, 2011 and 2010, respectively, and are reflective of certain production tax incentives. The increase in rate from 2010 was primarily due to a higher percentage of our oil revenues being subject to taxation in the State of Texas.

Depreciation, Depletion, and Amortization. DD&A expense increased year-over-year due to a 35% and 20% increase in production from 2011 and 2010, respectively, partially offset by lower DD&A rates driven by significant additions of proved reserves, primarily in the Gates Ranch area.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead costs of $6.0 million, decreased in 2012 from 2011. The decrease in 2012 was primarily

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related to a $10.5 million decrease in stock-based compensation expense driven by our performance share units, partially offset by a $2.2 million increase in rent expense related to our new office location and a $1.8 million increase in other administrative costs.

In 2011, general and administrative costs, net of capitalized exploration and development overhead costs of $7.0 million, increased from 2010. The increase in 2011 was primarily related to a $14.9 million increase in stock-based compensation expense as a result of our increased stock price and incentive compensation related to performance share units, a $5.3 million increase in consultant costs related to various internal projects and divestiture activities, and a $0.2 million increase in other administrative costs, partially offset by a decrease of $1.5 million in salaries, wages and bonuses due to lower headcount as a result of closing our former Denver office.

Total Other Expense

Total other expense includes Interest expense, net of interest capitalized, Interest income and Other income/expense, net. Total other expense increased $2.2 million in 2012 from 2011 primarily due to increased borrowings under our Credit Facility.

Total other expense decreased $3.8 million in 2011 from 2010 primarily due to our repayment of $100.0 million under the Credit Facility in April 2011, which resulted in lower interest expense and an increase in capitalized interest resulting from an increase in our weighted average interest rate. The weighted average interest rate of 8.45% in 2011 was higher than the 2010 rate of 7.06% due to the higher interest rate associated with the Senior Notes, which were issued in April 2010.

Provision for Income Taxes

Our 2012 income tax expense was $95.9 million. For the year ended December 31, 2012, the effective tax rate was 37.6% compared to the effective tax rate of 35.7% for the year ended December 31, 2011 and 58.2% for the year ended December 31, 2010. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate primarily due to the effect of state taxes, the non-deductibility of certain incentive compensation and a valuation allowance against certain state deferred tax assets.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2012, we had a net deferred tax liability of $9.8 million, compared to a net deferred tax asset of approximately $85.2 million at December 31, 2011, resulting primarily from the difference between the book and tax bases of our oil and natural gas properties and net operating loss carryforwards (NOLs).

In connection with our asset divestitures in 2010, 2011 and 2012, we concluded that it was more likely than not that the NOLs and other deferred tax assets in those states impacted by our divestitures would not be realized. Therefore, valuation allowances were established for these items as well as state NOLs in other jurisdictions in which we previously operated but had since divested of operating assets. Annually, changes in our valuation allowance are made to reflect revised estimates of the utilization of state deferred tax assets. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow and borrowings under our Credit Facility, which can be accessed as needed to supplement operating cash flow.

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Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising commodity prices. The effects of these derivative transactions on our oil, NGL and natural gas sales are discussed above under Results of Operations Revenues. The majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels. Economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program or raising additional debt or equity capital.

Senior Secured Revolving Credit Facility. On April 25, 2012, we entered into an amendment to our Credit Facility. Under this amendment, among other things, our borrowing base and commitments were increased from $325.0 million to $625.0 million and our capacity to hedge our production was increased. Availability under the Credit Facility is restricted to a borrowing base and committed amount, which are subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements as well as asset divestitures. The amount of the borrowing base and committed amount is affected by a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending may result in a reduced level of reserves that could lower our borrowing base and committed amount.

As of December 31, 2012, we had $210.0 million outstanding with $415.0 million of available borrowing capacity under the Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% and mature in May 2016. The weighted average borrowing rate for the year ended December 31, 2012 under the Credit Facility was 1.89%. Borrowings under the Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of our domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are also subject to certain financial covenants, including the requirement to maintain (i) a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, after giving pro forma effect to acquisitions and divestitures. At December 31, 2012, our current ratio as defined under the agreement was 3.1 and our leverage ratio was 0.9. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2012. In early 2013, we borrowed an additional $15.0 million under the Credit Facility and our borrowing capacity was reduced to $400.0 million.

Second Lien Term Loan. Our amended and restated term loan (the Restated Term Loan) of $20.0 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by second priority liens on substantially all of the Company s assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, $0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit our ability to, among other things, incur additional indebtedness; pay dividends on our capital stock or purchase,

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repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. At December 31, 2012, we were in compliance with the terms and provisions as contained within the Indenture. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under our Credit Facility and $80.0 million of variable rate borrowings outstanding under our Restated Term Loan, and to pay fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, we exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

Total Indebtedness. As of December 31, 2012, we had total outstanding indebtedness of $410.0 million and for the year ended December 31, 2012, our weighted average borrowing rate was 7.18%.

Working Capital

Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and the impact of our outstanding derivative instruments. At December 31, 2012 and 2011, we had working capital deficits of $21.3 million and $36.0 million, respectively. We believe we have adequate availability under our Credit Facility and liquidity available to meet our working capital requirements.

Cash Flows

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Cash flows provided by operating activities	$ 370,630	$ 299,537	$ 176,861
Cash flows used in investing activities	(533,641)	(190,363)	(251,621)
Cash flows provided by (used in) financing activities	152,747	(103,758)	55,138
Net (decrease) increase in cash and cash equivalents	$ (10,264)	$ 5,416	$ (19,622)

Operating Activities. Net cash provided by operating activities in 2012 and 2011 reflects higher operating income as a result of increased liquids production and an expansion of our production base to include a greater mix of crude oil and NGLs, which continue to be priced at more favorable levels than natural gas. Net cash provided by operating activities in 2010 reflects lower operating income as a result of 78% of our production base being attributable to natural gas production.

Investing Activities. Net cash used in investing activities in 2012 reflects additions to oil and natural gas assets of $622.2 million. These capital expenditures were used to drill 85 gross wells, the majority of which were located in the Eagle Ford area. Additions to oil and natural gas assets were partially offset by net asset divestiture proceeds of $88.5 million from the 2012 divestiture of our Lobo and partial Olmos assets.

Net cash used in investing activities in 2011 reflects additions to oil and natural gas assets of $433.0 million. These capital expenditures were used to drill 64 gross wells, the majority of which were located in the Eagle Ford area. Additions to oil and natural gas assets were partially offset by net asset divestiture proceeds of $242.6 million primarily from the 2011 divestitures of our Sacramento Basin assets in California and our DJ Basin assets in Colorado.

Net cash used in investing activities in 2010 reflects additions to oil and natural gas assets of $328.9 million and our acquisition of the remaining 30% working interest in wells in the Catarina Field in South Texas for $5.9 million. Capital expenditures in 2010 were used to drill 127 gross wells, the majority of which were located in the DJ Basin in Colorado. Capital additions were partially offset by net asset divestiture proceeds of $83.1 million primarily from the 2010 divestitures of our Pinedale and San Juan assets located in Wyoming and

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New Mexico, our Arklatex assets located in Arkansas, Oklahoma, Mississippi, Texas and Louisiana, and our Gulf Coast Sabine Lake asset.

Financing Activities. Net cash provided by financing activities in 2012 primarily reflects net borrowings of $180.0 million under the Credit Facility, partially offset by the prepayment of $20.0 million of indebtedness under the Restated Term Loan and treasury stock purchases of $6.2 million.

Net cash used in financing activities in 2011 reflects payments of $100.0 million under the Credit Facility, treasury stock purchases of $4.4 million and payments of $3.2 million in deferred loan fees, partially offset by proceeds from exercised stock options of $3.8 million.

Net cash provided by financing activities in 2010 reflects the proceeds from the issuance of our $200.0 million Senior Notes and proceeds from exercised stock options of $4.8 million, partially offset by the payment of $80.0 million under the Restated Term Loan, net payments of $60.0 million under the Credit Facility, payments of $6.3 million in deferred loan fees and treasury stock purchases of $3.4 million.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps, basis swaps, NYMEX roll swaps and costless collars for each year through 2015. Our fixed price swap, basis swap, NYMEX roll swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on a portion of our expected production from existing wells upon inception of the derivative instruments.

As of December 31, 2012, our derivative instruments are with counterparties who are lenders under our Credit Facility or were lenders under our Credit Facility upon origination of the derivative instrument. This practice allows us to satisfy any need for any margin obligation resulting from an adverse change in the fair market value of the derivative contracts with the collateral securing our Credit Facility, thus eliminating the need for independent collateral postings. As of December 31, 2012, we had no deposits for collateral in regard to our commodity derivative instruments.

Capital Requirements

Our capital expenditures for the year ended December 31, 2012 were $653.0 million, including capitalized internal costs directly identified with acquisition, exploration and development activities of $6.0 million and capitalized interest of $3.8 million. We have plans to execute a capital program in 2013 of $640 million to $700 million that will be funded from internally generated cash flows supplemented by borrowings under our Credit Facility.

Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is management s belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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Contractual Obligations. At December 31, 2012, the aggregate amounts of our contractually obligated payment commitments for the next five years and thereafter were as follows:

	Payments Due By Period				
	Total	2013	2014 to 2015	2016 to 2017	Thereafter
	(In thousands)				
Senior secured revolving line of credit	$ 210,000	$	$	$ 210,000	$
Senior notes	200,000				200,000
Operating leases	51,372	6,804	9,135	8,702	26,731
Interest payments on long-term debt (1)	113,023	23,116	46,232	38,209	5,466
Drilling rig commitments	10,292	10,292			
Completion service agreements	5,250	5,250			
Firm transportation and processing	299,031	29,273	68,633	67,197	133,928
Total contractual obligations	$ 888,968	$ 74,735	$ 124,000	$ 324,108	$ 366,125

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2012.

Asset Retirement Obligations. At December 31, 2012, we had total liabilities of $8.4 million related to asset retirement obligations (ARO) that are excluded from the table above. Of the total ARO, the current portion of $2.4 million at December 31, 2012 was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of $6.0 million at December 31, 2012 was included in Other long-term liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations. See Item 8. Financial Statements and Supplementary Data, Note 9 Asset Retirement Obligations.

Firm Oil and Natural Gas Transportation and Processing Commitments. We have commitments for the transportation and processing of our production in the Eagle Ford area and have an aggregate minimum commitment to deliver 7.6 MMBbl of oil by early 2018 and 404 million MMBtu of natural gas by the end of 2023. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume under these commitments. Currently, we have insufficient production to meet all of these contractual commitments. However, we intend to completely fulfill the delivery commitments by 2015 with production from the development of our proved reserves, as well as the development of resources not yet characterized as proved reserves, in the Eagle Ford area. As we develop our Eagle Ford assets, we intend to enter into additional transportation and processing commitments in the future that may expose us to additional volume deficiency payments. See Items 1 and 2, Business and Properties for a description of our production and proved reserves and Item 8. Financial Statements and Supplementary Data, Note 11 Commitments and Contingencies.

Contingencies. We are party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, we do not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of these financial statements requires us to make estimates and assumptions

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about future events and apply judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the related disclosure of contingent assets and liabilities and proved oil, NGL and natural gas reserves. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8. Financial Statements and Supplementary Data, Note 2 Summary of Significant Accounting Policies, for a discussion of additional accounting policies and estimates made by management.

Proved Oil, NGL and Natural Gas Reserves

The engineering estimates of proved oil, NGL and natural gas reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil, NGL and natural gas reserves are the estimated quantities of oil, NGL and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently provided to NSAI, which performs a year-end reserve report audit. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil, NGL and natural gas prices, operating and future development costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impacts oil and natural gas property amounts in the Consolidated Balance Sheet and the DD&A amounts in the Consolidated Statement of Operations. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures.

Full Cost Accounting Method

We use the full cost method to account for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and accumulated into a cost center (the amortization base), whether or not the activities to which they apply are successful. This includes any internal costs that are directly related to acquisition, exploration and development activities but does not include any costs associated with production and general corporate activities, which are expensed in the period incurred. The capitalized costs of our oil and natural gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment. Upon evaluation or impairment, these costs are transferred to the full cost pool and amortized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The application of the full cost method generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method.

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Depreciation, Depletion and Amortization

The quantities of estimated proved oil, NGL and natural gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future depletion expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or a ceiling test write-down. A five percent positive revision to proved reserves would decrease our depletion rate by approximately $0.53 per Boe while a five percent negative revision to proved reserves would increase our depletion rate by approximately $0.60 per Boe. This estimated impact is based on current data at December 31, 2012, and actual events could result in different adjustments to depletion expense.

Costs Withheld From Amortization

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage, wells currently drilling, suspended wells and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with major development projects may be temporarily excluded from amortization due to the size and complexity of the resource play. Incurred and estimated future development costs are allocated between completed and future work. Any costs withheld from the amortization base are subsequently included in the amortization base upon the earlier of when proved reserves are recorded or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, remaining lease terms, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2012, our full cost pool had approximately $95.5 million of costs excluded from the amortization base.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment, and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to plug and abandon wells, dismantle and relocate or dispose of our production platforms, gathering systems and related structures, and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the property s geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants and the operator of any of our non-operated properties. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

We provide for future abandonment costs in accordance with authoritative guidance for accounting for asset retirement obligations. We record a liability for the discounted fair value of an asset retirement obligation in the period in which it is incurred, and we capitalize the corresponding cost amount by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

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Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of costs associated with our oil and natural gas properties that can be capitalized on our balance sheet. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and natural gas properties pursuant to authoritative guidance, and estimated future income taxes thereon. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, such write-down would reduce earnings and stockholders equity in the period of occurrence and result in lower DD&A expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The current ceiling calculation utilizes a trailing twelve-month first-day-of-the-month historical unweighted average price. The costs in effect as of the last day of the quarter or annual period are held constant. Given the fluctuation of oil, NGL and natural gas prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If oil, NGL and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and natural gas properties could occur in the future. For more information regarding the full cost ceiling limitation, refer to Item 8. Financial Statements and Supplementary Data, Note 2 Summary of Significant Accounting Policies.

Derivative Transactions and Activities

We enter into derivative transactions to hedge against changes in oil, NGL and natural gas prices primarily through the use of fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. We have entered into a series of derivative transactions to hedge a portion of our expected oil, NGL and natural gas production through 2015.

These transactions are recorded in our financial statements in accordance with authoritative guidance for accounting for derivative instruments and hedging activities. Although not risk-free, we believe these agreements reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with authoritative guidance, all derivative instruments, unless designated as normal purchase and normal sale, are recorded on the balance sheet at fair market value. Effective January 1, 2012, we elected to de-designate all of our commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included $2.6 million ($1.6 million after tax) of unrealized gains, representing the mark-to-market value of our cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and are being reclassified into earnings as the underlying hedged transactions affect earnings. With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings within Revenues Derivative instruments on our Consolidated Statement of Operations, rather than in Accumulated other comprehensive income. These mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The cash flow impact occurs upon settlement of the underlying contract.

Fair Value Measurements

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. Our financial assets and liabilities are measured at fair value on a recurring basis. Our non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, are recognized at fair value on a non-recurring basis but at least annually. For our non-financial assets and liabilities, we are required to disclose information that enables users of our financial statements to assess the inputs used to develop these measurements. Changes in fair value associated with both financial and non-financial assets and liabilities are recorded in our Consolidated Statement of Operations. See Item 8. Financial Statements and Supplementary Data, Note 7 Fair Value Measurements.

Stock-Based Compensation

We account for stock-based compensation in accordance with applicable authoritative guidance. Stock-based compensation expense for restricted stock is estimated at the grant date based on the award s fair value, which is equal to the average high and low common stock price on the date of grant. Such fair value is recognized as expense over the requisite service period. Stock-based compensation expense for options is estimated at the grant date based on the award s fair value as calculated by the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

Stock-based compensation expense for performance share units (PSUs) is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the anticipated vesting percentage. Compensation expense for performance-based awards is recognized when it is probable that performance conditions will be achieved and such awards are expected to vest. The Compensation Committee of the Board of Directors retains discretion beyond the stated performance metrics to ensure it has the ability to reward a focus on behaviors that improves total shareholder return over the long-term and promote various corporate goals. The Compensation Committee has not adopted a policy that all compensation must be deductible for federal income tax purposes, and therefore we may make payments that are not fully deductible if we believe they are necessary to achieve corporate objectives and protect shareholder interests. See Item 8. Financial Statements and Supplementary Data, Note 12 Stock-Based Compensation.

Revenue Recognition

Oil, NGL and natural gas revenue from our interests in producing wells is recognized upon delivery and passage of title, using the sales method for gas imbalances, net of any royalty interests in the produced product in accordance with the particular contractual provisions of the lease. If our sales of production volumes for a well exceed our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. We record our share of revenues based on sales volumes and contracted sales prices, adjusted for basis and quality differentials. In addition, oil, NGL and natural gas volumes sold are not significantly different from our share of production.

Income Taxes

We recognize deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. These deferred tax assets and liabilities are measured using the enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled, respectively. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Accruals for deferred tax assets and liabilities are subject to a considerable amount of judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Material changes in these accruals may occur in the future based on future taxable income, changes in legislation and feasible tax planning strategies. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. See Item 8. Financial Statements and Supplementary Data, Note 13 Income Taxes.

Recent Accounting Developments

The following recently issued accounting development will be applied and affect the Company in future periods.

Offsetting Assets and Liabilities. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance requiring entities to disclose both gross information and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of U.S. GAAP and those entities that prepare their financial statements on the basis of IFRS. In January 2013, the FASB issued additional guidance clarifying the scope of these disclosures to include bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. This guidance will be required for interim and annual reporting periods effective January 1, 2013 and will be retrospectively applied. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

Off-Balance Sheet Arrangements

At December 31, 2012, we did not have any off-balance sheet arrangements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Price Risk and Related Derivative Activities.

Commodity Price Risk. Our major market risk exposure is in the pricing of our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing price for crude oil and spot market prices applicable to our natural gas and NGL production. Pricing for oil, NGL and natural gas production has been volatile and unpredictable for several years and we expect this volatility to continue in the future. Accordingly, we use certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Although not risk-free, we believe these activities will reduce commodity price fluctuations and thereby enable us to achieve a more predictable cash flow.

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Our fixed price swap agreements are used to fix the sales price for our anticipated future NGL and natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. Should the market for this instrument become attractive, we have the ability to enter into fixed price swap agreements for our anticipated future oil production, as well as add additional NGL and natural gas fixed price swaps.

Our basis swaps and NYMEX roll swaps are used to fix the variability between two price indexes and the NYMEX roll price, respectively, for our anticipated future oil production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us.

Our costless collar agreements are used to fix the variability in sales price within a floor price and ceiling price for our anticipated future oil and natural gas production. These instruments are settled monthly when required as defined in each instrument. When the floating market price exceeds the ceiling price, we pay our counterparty. When the floor price exceeds the floating market price, our counterparty is required to make payment to us. If the floating market price is within the floor and ceiling prices, no payments are required by either us or the counterparties. Should the market for this instrument become attractive, we have the ability to enter into costless collar agreements for our anticipated future NGL production, as well as add additional oil and natural gas costless collars.

As of December 31, 2012, we had open crude oil derivative contracts in a net asset position with a fair value of $3.9 million. A 10% increase in crude oil prices would reduce the fair value by approximately $7.9 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $7.6 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of December 31, 2012, we had open NGL derivative contracts in a net asset position with a fair value of $11.3 million. A 10% increase in NGL prices would reduce the fair value by approximately $17.3 million, while a 10% decrease in NGL prices would increase the fair value by approximately $17.3 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of December 31, 2012, we had open natural gas derivative contracts in a net asset position with a fair value of $5.4 million. A 10% increase in natural gas prices would reduce the fair value by approximately $13.2 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $13.6 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

These fair value changes assume volatility based on prevailing market parameters at December 31, 2012.

These transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement, or in the event of non-performance under the contracts by the counterparties to our derivative agreements.

As of December 31, 2012, our derivative instruments are with counterparties who are lenders under our Credit Facility or were lenders under our Credit Facility upon origination of the derivative instrument. This practice has allowed us to satisfy any need for margin obligations resulting from an adverse change in the fair

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market value of the derivative contracts with the collateral securing our Credit Facility, thus eliminating the need for independent collateral postings. As of December 31, 2012, we had no deposits for collateral relating to our commodity derivative instruments. Our derivative instrument assets and liabilities relate to commodity hedges that represent the difference between hedged prices and future market prices on hedged volumes of the commodities as of December 31, 2012. We evaluated non-performance risk using the current credit default swap values for the counterparties and recorded a downward adjustment to the fair value of our derivative instruments in the amount of $0.1 million as of December 31, 2012. We currently do not know of any circumstances that would limit access to our Credit Facility or require a change in our debt or hedging structure.

We entered into oil, NGL and natural gas price derivative contracts with respect to a portion of our expected production through 2015. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to exceed the price established by the contract. As of December 31, 2012, 83% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 17% at Light Louisiana Sweet; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 100% of our total natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel.

We utilize counterparty and third party broker quotes to determine the valuation of our derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant NYMEX futures contracts and exchange traded contracts, if deemed necessary, for each derivative settlement location. We mark-to-market the fair values of our derivative instruments on a quarterly basis and 100% of our commodity derivative assets and liabilities are considered Level 3 instruments.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors

and Stockholders of Rosetta Resources Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of cash flows and of stockholders equity present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries (the Company) at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Annual Report on Internal Control Over Financial Reporting appearing under Item 9A Controls and Procedures. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 2 and 6 to the financial statements, the Company discontinued hedge accounting effective January 1, 2012.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 26, 2013

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Item 8. Financial Statements and Supplementary Data

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 36,786	$ 47,050
Accounts receivable, net	103,828	77,374
Derivative instruments	14,437	10,171
Prepaid expenses	5,742	2,962
Deferred income taxes	311	11,015
Other current assets	1,456	2,942
Total current assets	162,560	151,514
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	2,829,431	2,297,312
Unproved/unevaluated properties, not subject to amortization	95,540	141,016
Gathering systems and compressor stations	104,978	38,580
Other fixed assets	16,346	9,494
	3,046,295	2,486,402
Accumulated depreciation, depletion and amortization including impairment	(1,808,190)	(1,657,841)
Total property and equipment, net	1,238,105	828,561
Other assets:		
Deferred loan fees	7,699	8,575
Deferred income taxes		74,150
Derivative instruments	6,790	1,633
Other long-term assets	262	912
Total other assets	14,751	85,270
Total assets	$ 1,415,416	$ 1,065,345
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 1,874	$ 2,489
Accrued liabilities	120,336	107,594
Royalties and other payables	61,637	50,689
Derivative instruments		6,788
Current portion of long-term debt		20,000
Total current liabilities	183,847	187,560

Long-term liabilities:		
Derivative instruments	563	1,351
Long-term debt	410,000	230,000
Deferred income taxes	10,086	
Other long-term liabilities	6,921	13,598
Total liabilities	$ 611,417	$ 432,509
Commitments and contingencies (Note 11)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2012 or 2011		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 53,145,853 shares and 52,630,483 shares at December 31, 2012 and 2011, respectively	53	52
Additional paid-in capital	830,539	810,794
Treasury stock, at cost; 581,717 shares and 450,173 shares at December 31, 2012 and 2011, respectively	(17,479)	(11,296)
Accumulated other comprehensive income	(63)	1,632
Accumulated deficit	(9,051)	(168,346)
Total stockholders equity	803,999	632,836
Total liabilities and stockholders equity	$ 1,415,416	$ 1,065,345

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

	Year Ended December 31, 2012	2011	2010
Revenues:			
Oil sales	$ 318,782	$ 156,284	$ 54,542
NGL sales	160,461	125,301	45,200
Natural gas sales	93,711	163,382	208,688
Derivative instruments	40,545	1,233	
Total revenues	613,499	446,200	308,430
Operating costs and expenses:			
Lease operating expense	42,429	34,900	51,085
Treating and transportation	51,826	22,316	6,963
Production taxes	16,722	12,073	5,953
Depreciation, depletion and amortization	154,223	123,244	116,558
General and administrative costs	68,731	75,256	56,332
Total operating costs and expenses	333,931	267,789	236,891
Operating income	279,568	178,411	71,539
Other expense (income):			
Interest expense, net of interest capitalized	24,316	21,291	27,073
Interest income	(7)	(42)	(38)
Other (income) expense, net	60	903	(1,087)
Total other expense	24,369	22,152	25,948
Income before provision for income taxes	255,199	156,259	45,591
Income tax expense	95,904	55,713	26,545
Net income	$ 159,295	$ 100,546	$ 19,046
Earnings per share:			
Basic	$ 3.03	$ 1.93	$ 0.37
Diluted	$ 3.01	$ 1.91	$ 0.37
Weighted average shares outstanding:			
Basic	52,496	51,996	51,381
Diluted	52,887	52,616	52,168

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Comprehensive Income

(In thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net income	$ 159,295	$ 100,546	$ 19,046
Other comprehensive (loss) income:			
Change in fair value of hedging instruments		2,033	42,632
Reclassification of (gain) on settled hedging instruments		(17,430)	(31,477)
Tax provision related to cash flow hedging instruments	968	5,770	(4,155)
Amortization of accumulated other comprehensive gain related to de-designated hedges	(2,663)		
Other comprehensive (loss) income	(1,695)	(9,627)	7,000
Comprehensive income	$ 157,600	$ 90,919	$ 26,046

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

	Year Ended December 31,		
	2012	**2011**	**2010**
Cash flows from operating activities:			
Net income	$ 159,295	$ 100,546	$ 19,046
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	154,223	123,244	116,558
Deferred income taxes	95,904	56,170	26,740
Amortization of deferred loan fees recorded as interest expense	2,856	2,248	2,828
Amortization of original issue discount recorded as interest expense			1,258
Stock-based compensation expense	18,539	29,010	14,147
Derivative instruments	(19,662)	(12,124)	(1,715)
Change in operating assets and liabilities:			
Accounts receivable	(26,454)	(41,215)	(11,337)
Prepaid expenses	(2,780)	(226)	852
Other current assets	680	287	961
Long-term assets	650	(450)	(316)
Accounts payable	(615)	(1,180)	1,390
Accrued liabilities	(19,382)	1,945	6,848
Royalties and other payables	10,948	37,409	(1,195)
Other long-term liabilities	(3,572)	(8,863)	796
Derivative instruments		12,736	
Net cash provided by operating activities	370,630	299,537	176,861
Cash flows from investing activities:			
Additions to oil and natural gas assets	(622,168)	(432,951)	(328,889)
Acquisition of oil and natural gas assets			(5,874)
Disposals of oil and natural gas assets	88,527	242,588	83,142
Net cash used in investing activities	(533,641)	(190,363)	(251,621)
Cash flows from financing activities:			
Borrowings on Credit Facility	290,000		64,000
Payments on Credit Facility	(110,000)	(100,000)	(124,000)
Issuance of Senior Notes			200,000
Repayments on Restated Term Loan	(20,000)		(80,000)
Deferred loan fees	(1,980)	(3,150)	(6,282)
Proceeds from stock options exercised	910	3,792	4,843
Purchases of treasury stock	(6,183)	(4,400)	(3,423)
Net cash provided by (used in) financing activities	152,747	(103,758)	55,138
Net (decrease) increase in cash	(10,264)	5,416	(19,622)
Cash and cash equivalents, beginning of year	47,050	41,634	61,256

Cash and cash equivalents, end of year	$ 36,786	$ 47,050	$ 41,634
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$ 20,834	$ 19,044	$ 22,987
Cash (received) paid for income taxes	$ (105)	$ (405)	$ 337
Supplemental non-cash disclosures:			
Capital expenditures included in accrued liabilities	$ 88,844	$ 57,546	$ 22,945

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

	Common Stock			Treasury Stock		Accumulated	Retained	
			Additional			Other	Earnings /	Total
			Paid-In			Comprehensive	Accumulated	Stockholders
	Shares	Amount	Capital	Shares	Amount	(Loss)/Income	Deficit	Equity
Balance at December 31, 2009	51,254,709	$ 51	$ 780,196	199,955	$ (3,473)	$ 4,259	$ (287,938)	$ 493,095
Stock options exercised	287,397	1	4,842					4,843
Treasury stock employee tax payment				143,138	(3,423)			(3,423)
Stock-based compensation			8,255					8,255
Issuance of common stock	488,898							
Comprehensive income:								
Net income							19,046	19,046
Change in fair value of derivative hedging instruments						42,632		42,632
Hedge settlements reclassified to income						(31,477)		(31,477)
Tax expense related to cash flow hedges						(4,155)		(4,155)
Comprehensive income								26,046
Balance at December 31, 2010	52,031,004	$ 52	$ 793,293	343,093	$ (6,896)	$ 11,259	$ (268,892)	$ 528,816
Stock options exercised	230,741		3,792					3,792
Treasury stock - employee tax payment				107,080	(4,400)			(4,400)
Stock-based compensation			13,709					13,709
Issuance of common stock	368,738							
Comprehensive income:								
Net income							100,546	100,546
Change in fair value of derivative hedging instruments						2,033		2,033
Hedge settlements reclassified to income						(17,430)		(17,430)
Tax expense related to cash flow hedges						5,770		5,770
Comprehensive income								90,919
Balance at December 31, 2011	52,630,483	$ 52	$ 810,794	450,173	$ (11,296)	$ 1,632	$ (168,346)	$ 632,836
Stock options exercised	69,862	1	910					911
Treasury stock - employee tax payment				131,544	(6,183)			(6,183)
Stock-based compensation			18,835					18,835
Issuance of common stock	445,508							
Comprehensive income:								
Net income							159,295	159,295
Hedge settlements reclassified to income						(2,663)		(2,663)
						968		968

Tax expense related to cash flow hedges								
Comprehensive income								157,600
Balance at December 31, 2012	53,145,853	$ 53	$ 830,539	581,717	$ (17,479)	$ (63)	$ (9,051)	$ 803,999

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company s operations are primarily located in South Texas, including its largest producing area in the Eagle Ford.

In preparing these financial statements, events occurring after December 31, 2012 through the release of these financial statements were evaluated by the Company to ensure that subsequent events meeting the criteria for recognition and/or disclosure in this report have been included.

Certain reclassifications of prior year balances have been made to conform with current year classifications. These reclassifications have no impact on net income.

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the Company s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, the outcome of pending litigation and environmental costs, stock-based compensation, valuation of derivative instruments, future development and abandonment costs, estimates related to certain oil, NGL and natural gas revenues and operating expenses, and the estimates of proved oil, NGL and natural gas reserve quantities that are used to calculate depletion and impairment of proved oil and natural gas properties.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

With respect to the current market environment for liquidity and access to credit, the Company, through banks participating in its credit facility, has invested available cash in interest and non-interest bearing demand deposit accounts in those participating banks and in money market accounts and funds whose investments are limited to U.S. Government securities, securities backed by the U.S. Government, or securities of U.S. Government agencies. The Company has followed this policy and believes this is an appropriate approach for the investment of Company funds.

Restricted Cash

As of December 31, 2012 and 2011, the Company had no restricted cash.

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Allowance for Doubtful Accounts

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances. As of December 31, 2012 and 2011, the Company had no allowance for doubtful accounts.

Oil and Natural Gas Properties

The Company follows the full cost method of accounting whereby all costs incurred in acquiring, exploring and developing properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized when incurred into cost centers that are established on a country-by-country basis. Such costs are amortized on a unit-of-production basis over reserves in the cost center in which they are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with unevaluated properties and significant development projects, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of reserves that ultimately result from the efforts as a whole, and are thus associated with the Company s reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $6.0 million, $7.0 million and $7.8 million of internal costs for the years ended December 31, 2012, 2011 and 2010, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment. Upon evaluation or impairment, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally reflected in the full cost pool, unless a significant portion of the pool or reserves is sold causing a significant change in the relationship between capitalized costs and proved reserves, in which case a gain or loss is calculated and recognized in the Consolidated Statement of Operations.

The Company assesses the impairment for oil and natural gas properties quarterly using a ceiling test to determine if impairment is necessary. This ceiling limits capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and natural gas properties pursuant to authoritative guidance, and estimated future income taxes thereon.

A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, a write-down would reduce earnings and impact shareholders equity in the period of occurrence and result in lower DD&A expense in the future.

It is possible that a write-down of the Company s oil and natural gas properties could occur in the event that oil and natural gas prices decline or the Company experiences significant downward adjustments to its estimated proved reserves.

Other Fixed Assets

Other fixed assets primarily include computer hardware and software, office leasehold, and furniture and fixtures, which are recorded at cost and depreciated on a straight-line basis over useful lives of five to seven years. Repair and maintenance costs are charged to expense as incurred while renewals and betterments are capitalized as additions to the related assets in the period incurred. Gains or losses from the disposal of other fixed assets are recorded in the period incurred. The net book value of other fixed assets that are retired or sold is charged to accumulated depreciation and the difference is recognized as a gain or loss in the Consolidated Statement of Operations in the period the retirement or sale transpires.

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Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment, and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to plug and abandon wells, dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. The Company develops estimates of these costs for each of its properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews its assumptions and estimates of future development and future abandonment costs on an annual basis.

The Company provides for future abandonment costs in accordance with authoritative guidance regarding the accounting for asset retirement obligations. A liability is recorded for the fair value of an asset retirement obligation in the period in which it is incurred and the corresponding cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Capitalized Interest

The Company capitalizes interest on capital invested in projects related to unevaluated properties and significant development projects. As proved reserves are established or impairment determined, the related capitalized interest is included in costs subject to amortization. The Company capitalized interest of $3.8 million, $5.5 million, and $4.0 million in 2012, 2011 and 2010, respectively.

Fair Value of Financial Instruments

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company s financial assets and liabilities are measured at fair value on a recurring basis and non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, are recognized at fair value on a non-recurring basis but at least annually. For non-financial assets and liabilities, the Company is required to disclose information that enables users to assess the inputs used to develop these measurements. Changes in fair value associated with both financial and non-financial assets and liabilities are recorded in the Consolidated Statement of Operations. See Note 7 Fair Value Measurements.

Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of cash, accounts receivable and derivative instruments. The Company s accounts receivable and derivative instruments are concentrated among entities engaged in the energy industry within the U.S. and financial institutions, respectively. The Company periodically assesses the financial condition of these entities and institutions and considers any possible credit risk to be minimal.

Deferred Loan Fees

Loan fees incurred in connection with the Company s Credit Facility, Restated Term Loan and Senior Notes (each as hereafter defined in Note 10 Debt and Credit Agreements) are recorded on the Company s Consolidated Balance Sheet as Deferred loan fees. The deferred loan fees are amortized to interest expense over the term of the related debt using the straight-line method, which approximates the effective interest method.

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Derivative Instruments and Activities

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, New York Mercantile Exchange (NYMEX) roll swaps and costless collars. The Company does not enter into derivative agreements for trading or other speculative purposes and the fair value of derivative contracts is presented on a net basis where the right of offset is provided for in the counterparty agreements. Effective January 1, 2012, the Company elected to de-designate all of its commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. See Note 6 Commodity Derivative Contracts and Other Derivatives for a more detailed discussion of derivative activities.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. There were no significant environmental liabilities as of December 31, 2012 or 2011.

Stock-Based Compensation

Stock-based compensation cost for restricted stock is estimated at the grant date based on the award s fair value, which is equal to the average high and low common stock price on the date of grant. Such fair value is recognized as expense over the requisite service period. Stock-based compensation cost for options is estimated at the grant date based on the award s fair value as calculated using the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

Stock-based compensation expense for performance share units (PSUs) is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the anticipated vesting percentage. Compensation expense for performance-based awards is recognized when it is probable that performance conditions will be achieved and such awards are expected to vest. The Compensation Committee of the Board of Directors retains discretion beyond the stated performance metrics to ensure it has the ability to reward a focus on behaviors that improve total shareholder return over the long-term and promote various corporate goals. The Compensation Committee has not adopted a policy that all compensation must be deductible for federal income tax purposes, and therefore the Company may make payments that are not fully deductible if it believes such payments are necessary to achieve corporate objectives and protect shareholder interests. See Note 12 Stock-Based Compensation.

Any excess tax benefit arising from the Company s stock-based compensation plans is recognized as a credit to additional paid-in capital when realized and is calculated as the amount by which the tax effect of the tax deduction received exceeds the deferred tax asset associated with the recorded stock-based compensation expense. Current authoritative guidance requires the cash flows that result from tax deductions in excess of the recorded compensation expense to be recognized as financing activities.

Preferred Stock

The Company is authorized to issue 5,000,000 shares of preferred stock with preferences and rights as determined by the Company s Board of Directors. As of December 31, 2012 and 2011, there were no shares of preferred stock outstanding.

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Treasury Stock

The Company repurchases shares that are surrendered by employees and certain directors to pay tax withholding upon the vesting of restricted stock awards. These repurchases are not part of a publicly announced program to repurchase shares of the Company s common stock, nor does the Company have a publicly announced program to repurchase shares of common stock. Treasury stock purchases are recorded at cost.

Revenue Recognition

Oil, NGL and natural gas revenue from our interests in producing wells is recognized upon delivery and passage of title, using the sales method for gas imbalances, net of any royalty interests or other profit interests in the produced product. Under the sales method, if our gas imbalance (amount of production sold in excess of amount entitled) exceeds our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which we have taken less than our ownership share of production unless the amount taken by other parties exceeds the estimate of their remaining reserves. There were no significant gas imbalances at December 31, 2012 or 2011.

Income Taxes

The Company uses the liability method of accounting for income taxes. Under this method, deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax bases of assets and liabilities. Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Authoritative guidance for accounting for uncertainty in income taxes requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent Accounting Developments

The following recently issued accounting development will be applied and affect the Company in future periods.

Offsetting Assets and Liabilities. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance requiring entities to disclose both gross information and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of U.S. GAAP and those entities that prepare their financial statements on the basis of IFRS. In January 2013, the FASB issued additional guidance clarifying the scope of these disclosures to include bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. This guidance will be required for interim and annual reporting periods effective January 1, 2013 and will be retrospectively applied. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

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(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31, 2012	December 31, 2011
	(In thousands)	
Oil, NGL and natural gas sales	$ 84,533	$ 62,068
State severance tax refunds	16,269	14,141
Joint interest billings	3,026	1,165
Total	$ 103,828	$ 77,374

There are no balances in accounts receivable that are considered to be uncollectible and an allowance was unnecessary as of December 31, 2012 and 2011.

(4) Property and Equipment, Net

The Company s total property, plant and equipment consists of the following:

	December 31, 2012	December 31, 2011
	(In thousands)	
Proved properties	$ 2,829,431	$ 2,297,312
Unproved/unevaluated properties	95,540	141,016
Gathering systems and compressor stations	104,978	38,580
Other fixed assets	16,346	9,494
Total	3,046,295	2,486,402
Less: Accumulated depreciation, depletion and amortization	(1,808,190)	(1,657,841)
Total property and equipment, net	$ 1,238,105	$ 828,561

Included in the Company s oil and natural gas properties are asset retirement costs of $15.1 million and $18.0 million as of December 31, 2012 and 2011, respectively, including additions of $4.7 million and $2.1 million for the years ended December 31, 2012 and 2011, respectively.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company s costs are included in one cost center because all of the Company s operations are located in the United States. The Company s ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of December 31, 2012, which were based on a West Texas Intermediate oil price of $91.21 per Bbl and a Henry Hub natural gas price of $2.76 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and natural gas properties at December 31, 2012 and as a result, no write-down was recorded.

The Company did not record any write-downs or impairments for the years ended December 31, 2012, 2011 and 2010. Effective January 1, 2012, the Company elected to de-designate all of its commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. As a result, there will be no future impact to the calculated ceiling value due to cash flow hedges, and there was no potential impairment absent the effects of hedging in 2011 and 2010.

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Capitalized costs excluded from DD&A as of December 31, 2012 and 2011, all of which are located onshore in the U.S., are as follows by the year in which such costs were incurred:

			December 31, 2012		
	Total	2012	2011	2010	Prior
			(In thousands)		
Development costs	$ 29,857	$ 29,857	$	$	$
Exploration costs	16,180	16,180			
Acquisition cost of undeveloped acreage	42,186	15,297	6,672	16,920	3,297
Capitalized interest	7,317	3,309	2,064	1,481	463
Total capitalized costs excluded from DD&A	$ 95,540	$ 64,643	$ 8,736	$ 18,401	$ 3,760

			December 31, 2011		
	Total	2011	2010	2009	Prior
			(In thousands)		
Development costs	$ 12,479	$ 12,479	$	$	$
Exploration costs	79,250	60,389	18,861		
Acquisition cost of undeveloped acreage	42,532	6,000	21,486	6,362	8,684
Capitalized interest	6,755	4,506	568	455	1,226
Total capitalized costs excluded from DD&A	$ 141,016	$ 83,374	$ 40,915	$ 6,817	$ 9,910

It is anticipated that development costs of $29.9 million will be included in oil and natural gas properties subject to amortization within one year. With respect to the remaining capitalized costs excluded from DD&A of $65.6 million, it is anticipated that these costs will be included in oil and natural gas properties subject to amortization within five years.

Property Acquisitions and Divestitures. On February 15, 2012, the Company entered into an agreement to sell its Lobo assets and a portion of its Olmos assets for $95.0 million, subject to customary post-closing adjustments and the receipt of appropriate consents for assignment. During the third quarter of 2012, the Company closed on the sale of the final portion of the properties. Proceeds from the closing of the divestiture were recorded as adjustments to the full cost pool, with no gain or loss recognized.

In February 2011, the Company executed purchase and sale agreements for the divestitures of its Sacramento Basin assets in California and its DJ Basin assets in Colorado for $200.0 million and $55.0 million, respectively. These asset divestitures were effective as of January 1, 2011 and were subject to post-closing purchase price adjustments. Proceeds from the divestitures were recorded as adjustments to the full cost pool, with no gain or loss recognized.

Gathering systems and compressor stations. The gross book value of the Company s gathering systems and compressor stations was $105.0 million and $38.6 million at December 31, 2012 and 2011, respectively, and is being depreciated on a straight-line basis over 15 years. Accumulated depreciation related to these assets at December 31, 2012 and 2011 was $5.7 million and $2.5 million, respectively. Depreciation expense associated with the gathering systems and compressor stations for the years ended December 31, 2012, 2011, and 2010 was $4.0 million, $2.3 million, and $3.2 million, respectively. In connection with divestitures in 2011, the Company sold certain of these assets primarily located in the Sacramento Basin in California with no gain or loss recognized.

Other fixed assets. Other fixed assets at December 31, 2012 and 2011 of $16.3 million and $9.5 million, respectively, consisted primarily of computer hardware and software, office leasehold and furniture and fixtures. Accumulated depreciation associated with Other fixed assets at December 31, 2012 and 2011 was $5.1 million and $5.9 million, respectively. For the years ended December 31, 2012, 2011 and 2010, depreciation expense for Other fixed assets was $1.4 million, $2.6 million and $2.1 million, respectively.

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(5) Deferred Loan Fees

As of December 31, 2012 and 2011, deferred loan fees, net were $7.7 million and $8.6 million, respectively. Total amortization expense for deferred loan fees was $2.9 million, $2.2 million and $2.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(6) Commodity Derivative Contracts and Other Derivatives

The Company is exposed to various market risks, including volatility in oil, NGL and natural gas prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company s oil, NGL and natural gas production.

At December 31, 2012, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Average Floor Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2013	Costless Collar	7,750	2,828,750	$ 80.16	$ 115.71
Crude oil	2014	Costless Collar	3,000	1,095,000	83.33	109.63
				3,923,750		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Fixed Prices per Bbl
Crude oil	2013	Basis Swap	1,875	684,375	$ 5.80
Crude oil	2013	NYMEX Roll Swap	1,875	684,375	(0.18)
				1,368,750	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Fixed Prices per Bbl
NGL-Ethane	2013	Swap	3,000	1,095,000	$ 14.43
NGL-Propane	2013	Swap	2,270	828,550	46.34
NGL-Isobutane	2013	Swap	705	257,325	69.30
NGL-Normal Butane	2013	Swap	730	266,450	66.86
NGL-Pentanes Plus	2013	Swap	795	290,175	86.27
NGL-Ethane	2014	Swap	2,000	730,000	15.28
NGL-Propane	2014	Swap	1,535	560,275	43.75
NGL-Isobutane	2014	Swap	480	175,200	66.71
NGL-Normal Butane	2014	Swap	475	173,375	64.54
NGL-Pentanes Plus	2014	Swap	510	186,150	83.96
				4,562,500	

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Product	Settlement Period	Derivative Instrument	Notional Daily Volume MMBtu	Total Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2013	Costless Collar	20,000	7,300,000	$ 3.50	$ 4.90
Natural gas	2014	Costless Collar	30,000	10,950,000	3.50	4.93
Natural gas	2015	Costless Collar	30,000	10,950,000	3.50	5.11
Natural gas	2013	Swap	20,000	7,300,000	3.98	
Natural gas	2014	Swap	20,000	7,300,000	3.98	
Natural gas	2015	Swap	10,000	3,650,000	3.95	
				47,450,000		

The Company s derivative instruments are with counterparties who are lenders under the Company s Credit Facility or were lenders under the Company s Credit Facility upon origination of the derivative instrument. This practice allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit Facility, thus eliminating the need for independent collateral postings. The Company s ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Government Regulation. As of December 31, 2012, the Company had no deposits for collateral relating to its commodity derivative positions.

Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company elected to de-designate all commodity contracts that were previously designated as cash flow hedges as of December 31, 2011, and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included $2.6 million ($1.6 million after tax) of unrealized net gains, representing the mark-to-market value of the Company s cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and are being reclassified into earnings as the underlying hedged transactions affect earnings. For the year ended December 31, 2012, the Company reclassified unrealized net gains of $2.7 million ($1.7 million after tax) into earnings from Accumulated other comprehensive income. The Company expects to reclassify $0.1 million of unrealized net losses during 2013 into earnings from Accumulated other comprehensive income.

With the election to de-designate hedging instruments, all of the Company s derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in Accumulated other comprehensive income. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The cash flow impact occurs upon settlement of the underlying contract.

Additional Disclosures about Derivative Instruments and Hedging Activities

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company s financial statements. The following table sets forth information on the location and amounts of the Company s derivative instrument fair values in the Consolidated Balance Sheet as of December 31, 2012 and 2011, respectively:

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Commodity derivative contracts	Location on Consolidated Balance Sheet	Asset (Liability) Fair Value December 31, 2012 (in thousands)	2011
Oil	Derivative instruments - current assets	$	$ (2,937)
Oil	Derivative instruments - non-current assets		1,254
Oil	Derivative instruments - current liabilities		(695)
Oil	Derivative instruments - long-term liabilities		(167)
NGL	Derivative instruments - current assets		(1,029)
NGL	Derivative instruments - current liabilities		(6,948)
NGL	Derivative instruments - long-term liabilities		(1,184)
Natural gas	Derivative instruments - current assets		14,137
	Total derivatives designated as hedging instruments	$	$ 2,431
Oil	Derivative instruments - current assets	$ 564	$
Oil	Derivative instruments - non-current assets	3,329	379
Oil	Derivative instruments - current liabilities		855
NGL	Derivative instruments - current assets	8,361	
NGL	Derivative instruments - non-current assets	3,534	
NGL	Derivative instruments - non-current liabilities	(563)	
Natural gas	Derivative instruments - current assets	5,512	
Natural gas	Derivative instruments - non-current assets	(73)	
	Total derivatives not designated as hedging instruments	$ 20,664	$ 1,234
	Total derivatives	$ 20,664	$ 3,665

The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the years ended December 31, 2012, 2011 and 2010, respectively:

Location on Consolidated Statement of Operations	Description of Gain (Loss)	December 31, 2012	2011 (in thousands)	2010
Oil sales	Loss reclassified from Accumulated OCI	$	$ (2,149)	$
NGL sales	Loss reclassified from Accumulated OCI		(10,190)	
Natural gas sales	Gain reclassified from Accumulated OCI		18,751	30,740
Interest expense, net of capitalized interest	Loss reclassified from Accumulated OCI			(978)
Natural gas sales (1)	Gain recognized in income		11,018	1,715
Derivative instruments	Gain recognized in income	20,883		
	Realized gain recognized in income	$ 20,883	$ 17,430	$ 31,477
Derivative instruments (2)	Gain recognized in income due to changes in fair value	$ 16,999	$ 1,233	$
Derivative instruments	Gain reclassified from Accumulated OCI	2,663		
	Unrealized gain recognized in income	$ 19,662	$ 1,233	$
	Total derivative gain recognized in income	$ 40,545	$ 18,663	$ 31,477

(1) For 2011, the amount represents the realized gains associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties. For 2010, the amount represents the realized gains associated with the 2010 termination of derivatives used to hedge production from the Company s divested Pinedale properties.

(2) For 2011, the amount represents the unrealized gain associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

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As a result of the Company s election to de-designate all commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and to discontinue hedge accounting prospectively, the Company recognized no gain or loss in Accumulated other comprehensive income for the year ended December 31, 2012. The Company recognized unrealized losses of $2.0 million and $42.6 million in Accumulated other comprehensive income for the years ended December 31, 2011 and 2010, respectively.

(7) Fair Value Measurements

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company s non-financial assets and liabilities were impaired during the year ended December 31, 2012, and because the Company had no other material assets or liabilities reported at fair value on a non-recurring basis, no additional disclosures are provided as of December 31, 2012.

As defined in the FASB s guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The FASB s guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

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The following table sets forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011.

	Fair value as of December 31, 2012			
	Level 1	Level 2	Level 3 (In thousands)	Total
Assets				
Money market funds (1)	$	$ 1,035	$	$ 1,035
Commodity derivative contracts			20,664	20,664
Total	$	$ 1,035	$ 20,664	$ 21,699

	Fair value as of December 31, 2011			
	Level 1	Level 2	Level 3 (In thousands)	Total
Assets				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			3,665	3,665
Total	$	$	$ 4,700	$ 4,700

(1) The value related to the money market funds was transferred from Level 3 to Level 2 in 2012 as a result of the Company s ability to obtain independent market-corroborated data.

The Company s Level 3 instruments include commodity derivative contracts which are measured based upon counterparty and third-party broker quotes. Although the Company compares the fair values derived from counterparties and third-party brokers with publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its counterparties or third-party brokers.

The following table presents a range of the unobservable inputs utilized in the fair value measurements of the Company s assets and liabilities classified as Level 3 instruments as of December 31, 2012:

Level 3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average
Oil NYMEX roll swap	13	Discounted cash flow	Forward price curve-NYMEX rolls swaps	$ (0.77)	$ 0.24	$ (0.20)
Oil basis swap	(3,409)	Discounted cash flow	Forward price curve-basis swaps	6.84	18.90	11.26
Oil costless collars	7,288	Option model	Forward price curve- costless collar option value	(6.32)	9.31	1.87
NGL swaps	13,885	Discounted cash flow	Forward price curve-swaps	10.08	86.05	30.15
NGL swaps	(2,553)	Discounted cash flow	Forward price curve-swaps	65.99	92.82	74.08
Natural gas swaps	3,636		Forward price curve-swaps	3.28	4.22	3.73

		Discounted cash flow				
Natural gas swaps	(745)	Discounted cash flow	Forward price curve-swaps	4.00	4.39	4.16
Natural gas costless collars	2,732	Option model	Forward price curve-costless collar option value	(0.32)	0.39	0.15
Natural gas costless collars	(183)	Option model	Forward price curve-costless collar option value	(0.47)	0.34	(0.02)
Total	$ 20,664					

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The determination of derivative fair values also incorporates a credit adjustment for non-performance risk, including the credit standing of the counterparties involved, and the impact of the Company s non-performance risk on its liabilities. The Company considered credit adjustments for its counterparties using their current credit default swap values in determining fair value and recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.1 million as of December 31, 2012.

The significant unobservable inputs for Level 3 derivative contracts include forward price curves and option values. Significant increases (decreases) in the quoted forward prices for commodities and option values generally lead to corresponding decreases (increases) in the fair value measurement of the Company s oil, NGL and natural gas derivative contracts.

The tables below present reconciliations of financial assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods.

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at December 31, 2010	19,657	1,035	20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)	(595)		(595)
Included in Other Comprehensive Income	2,033		2,033
Purchases, Issuances and Settlements			
Settlements	(28,448)		(28,448)
Purchases	11,018		11,018
Transfers in and out of Level 3			
Balance at December 31, 2011	$ 3,665	$ 1,035	$ 4,700
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	37,882		37,882
Included in Other Comprehensive Income			
Purchases, Issuances and Settlements			
Settlements	(20,883)		(20,883)
Purchases			
Transfers in and out of Level 3 (2)		(1,035)	(1,035)
Balance at December 31, 2012	$ 20,664	$	$ 20,664

(1) Includes an unrealized derivative gain of $1.2 million associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps, which did not qualify for hedge accounting.

(2) The value related to the money market funds was transferred from Level 3 to Level 2 in 2012 as a result of the Company s ability to obtain independent market-corroborated data.

Fair Value of Other Financial Instruments

All of the Company s financial instruments, except derivatives, are presented on the balance sheet at carrying value. As of December 31, 2012, the carrying value of cash and cash equivalents (excluding money market funds), other current assets and current liabilities reported in the Consolidated Balance Sheet approximate fair value because of their short-term nature, and all such financial instruments are considered Level 1 instruments.

The Company s debt consists of publicly traded Senior Notes (defined below) and borrowings under the Credit Facility (defined below). The fair value of the Company s Senior Notes is based upon an unadjusted quoted market price and is considered a Level 1 instrument. The Company s borrowings under the Credit Facility

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approximate fair value as the interest rates are variable and reflective of market rates, and are therefore considered a Level 1 instrument. As of December 31, 2012 and 2011, the estimated fair value of total debt was $432.5 million and $267.5 million, respectively.

(8) Accrued Liabilities, Royalties and Other Payables

The Company s accrued liabilities consist of the following:

	December 31,	
	2012	2011
	(In thousands)	
Accrued capital costs	$ 88,844	$ 57,546
Accrued payroll and employee incentive expense	10,436	33,500
Accrued lease operating expense	9,605	7,310
Accrued interest	4,582	3,958
Asset retirement obligation	2,440	1,637
Other	4,429	3,643
Total	$ 120,336	$ 107,594

At December 31, 2012, Royalties and other payables of $61.6 million includes $39.5 million of royalty revenues payable to landowners, $10.2 million of accrued transportation costs and $11.9 million of other operating liabilities.

(9) Asset Retirement Obligations

The following table provides a rollforward of the Company s asset retirement obligations (ARO). Liabilities incurred during the period include additional obligations. Liabilities settled during the period include payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Activity related to the Company s ARO is as follows:

	For the Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
ARO at the beginning of the period	$ 14,313	$ 27,934	$ 28,920
Liabilities incurred during period	866	2,096	629
Liabilities settled during period	(8,538)	(20,395)	(4,130)
Revision of previous estimate	935	3,454	322
Accretion expense	824	1,224	2,193
ARO at the end of the period	$ 8,400	$ 14,313	$ 27,934

As of December 31, 2012 and 2011, the current portion of ARO of $2.4 million and $1.6 million, respectively, was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of $6.0 million and $12.7 million as of December 31, 2012 and 2011, respectively, was included in Other long-term liabilities on the Consolidated Balance Sheet. The decrease in ARO in 2012 was primarily due to adjustments for obligations assumed by the purchasers of divested properties of approximately $6.6 million.

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(10) Debt and Credit Agreements

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Credit Facility	$ 210,000	$ 30,000
Restated Term Loan		20,000
Senior Notes	200,000	200,000
Total debt	$ 410,000	$ 250,000
Less:		
Current portion of long-term debt		(20,000)
Total long-term debt	$ 410,000	$ 230,000

Senior Secured Revolving Credit Facility. On April 25, 2012, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Facility (the Credit Facility). Under this amendment, among other things, the Company s borrowing base and commitments were increased from $325.0 million to $625.0 million and the Company s capacity to hedge its production was increased. Availability under the Credit Facility is restricted to a borrowing base and committed amount, which are subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company s hedging arrangements as well as asset divestitures. The amount of the borrowing base and committed amount is affected by a number of factors, including the Company s level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could lower the borrowing base and committed amount.

As of December 31, 2012, the Company had $210.0 million outstanding with $415.0 million of available borrowing capacity under its Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% and mature in May 2016. The weighted average borrowing rate for the year ended December 31, 2012 under the Credit Facility was 1.89%. Borrowings under the Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of the Company s domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of the Company s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is also subject to certain financial covenants, including the requirement to maintain (i) a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2012, the Company s current ratio as defined under the agreement was 3.1 and the leverage ratio was 0.9. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. In early 2013, the Company borrowed an additional $15.0 million under the Credit Facility and the borrowing capacity was reduced to $400.0 million.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) of $20.0 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by

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second priority liens on substantially all of the Company s assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, $0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the Senior Notes) in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit the Company s ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company s restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under the Credit Facility and $80.0 million of variable rate borrowings outstanding under the Restated Term Loan and to pay fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

Total Indebtedness. As of December 31, 2012, the Company had total outstanding indebtedness of $410.0 million, and for the year ended December 31, 2012 the Company s weighted average borrowing rate was 7.18%. Other than indebtedness under the Credit Facility that becomes due in 2016, the Company does not have any debt that matures within the five years ending December 31, 2017.

(11) Commitments and Contingencies

Firm Oil and Natural Gas Transportation and Processing Commitments. The Company has commitments for the transportation and processing of its production in the Eagle Ford area and has an aggregate minimum commitment to deliver 7.6 MMBbls of oil by early 2018 and 404 million MMBtus of natural gas by the end of 2023. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume under these commitments. Currently, the Company has insufficient production to meet all of these contractual commitments. However, the Company intends to completely fulfill the delivery commitments by 2015 with production from the development of its proved reserves, as well as the development of resources not yet characterized as proved reserves, in the Eagle Ford area. As the Company develops its Eagle Ford assets, it intends to enter into additional transportation and processing commitments in the future that may expose the Company to additional volume deficiency payments. As of December 31, 2012, the Company has accrued deficiency fees of $5.2 million and expects to continue to accrue additional deficiency fees under its current commitments until 2014. Future obligations under firm oil and natural gas transportation and processing agreements as of December 31, 2012 are as follows:

	December 31, 2012 (In thousands)
2013	$ 29,273
2014	34,403
2015	34,230
2016	33,809
2017	33,388
Thereafter	133,928
	$ 299,031

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors to execute the Company s Eagle Ford area drilling program, and

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payments under these commitments are accounted for as capital additions to oil and gas properties. As of December 31, 2012, the Company had no outstanding drilling rig commitments with terms greater than one year and minimum contractual commitments due in the next twelve months were $10.3 million. As of December 31, 2012, the Company s minimum contractual commitments for completion services agreements for the stimulation, cementing and delivery of drilling fluids were $5.3 million.

Lease Obligations and Other Commitments. The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $5.7 million, $3.4 million and $5.0 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2012 were as follows:

	December 31, 2012 (In thousands)
2013	$ 6,804
2014	4,875
2015	4,260
2016	4,314
2017	4,388
Thereafter	26,731
	$ 51,372

Contingencies. The Company is party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability the Company may ultimately incur with respect to any such proceeding may be in excess of amounts currently accrued, if any. After considering the Company s available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, the Company does not believe any such matter will have a material adverse effect on the Company s financial position, results of operations or cash flows.

(12) Stock-Based Compensation

Stock-based compensation expense includes the expense associated with equity awards granted to employees and directors and the expense associated with the Performance Share Units (PSUs) granted to executive management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Total stock-based compensation expense	$ 18,835	$ 29,676	$ 14,712
Capitalized in oil and gas properties	(296)	(666)	(565)
Net stock-based compensation expense	$ 18,539	$ 29,010	$ 14,147

The Company had an associated tax benefit of $2.8 million, $10.6 million and $5.0 million, respectively, related to stock-based compensation.

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2005 Long-Term Incentive Plan

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan (the Plan) whereby stock is granted to employees, officers and directors of the Company. The Plan allows for the grant of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards. Employees, non-employee directors and other service providers of the Company and its affiliates who, in the opinion of the Compensation Committee or another Committee of the Board of Directors (the Committee), are in a position to make a significant contribution to the success of the Company and the Company s affiliates are eligible to participate in the Plan. The Plan provides for administration by the Committee, which determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the Plan s terms. The Plan also provides for the immediate vesting of awards in the event of the death or disability of a participant. The maximum number of shares available for grant under the Plan was increased from 3,000,000 shares to 4,950,000 shares by vote of the shareholders in 2008. The shares available for grant include these 4,950,000 shares plus any shares of common stock that become available under the Plan for any reason other than exercise, such as shares traded for the related tax liabilities of employees. The maximum number of shares of common stock available for grant of awards under the Plan to any one participant is (i) 300,000 shares during any fiscal year in which the participant begins work for the Company and (ii) 200,000 shares during each fiscal year thereafter.

Stock Options

Prior to 2010, the Company granted stock options under the Plan, which generally expire ten years from the date of grant. The exercise price of the option could not be less than the fair market value per share of the Company s common stock on the grant date and the majority of options vested over a three year period. During the years ended December 31, 2012, 2011 and 2010, no options were granted to employees, officers or directors of the Company and all options granted prior to 2010 under the Plan have vested. Compensation expense was recognized ratably over the requisite service period.

The following table summarizes information related to outstanding and exercisable options held by the Company s employees and directors at December 31, 2012:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands) (1)
Outstanding at December 31, 2010	811,254	$ 14.36		
Granted				
Exercised	(230,741)	16.55		
Forfeited				
Outstanding at December 31, 2011	580,513	$ 13.48		
Granted				
Exercised	(69,862)	13.21		
Forfeited				
Outstanding at December 31, 2012	510,651	$ 13.52		
Options vested and exercisable at December 31, 2012	510,651	$ 13.52	4.92	$ 15,826

(1) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock, at the indicated date, exceeds the exercise price of the option.

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2012, 2011 and 2010 was less than $0.1 million, $0.4 million and $0.6 million, respectively. As of December 31, 2012, the Company has no unrecognized expense because all outstanding stock options have vested.

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The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $2.3 million, $7.1 million and $4.1 million, respectively.

Restricted Stock

The Company has granted restricted stock to employees and directors under the Plan. The majority of the Company s restricted stock grants vest over a three-year period. The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company has assumed an annual forfeiture rate of 10% for these awards based on the Company s history for this type of award to various employee groups.

The following table summarizes information related to restricted stock held by the Company s employees and directors at December 31, 2012:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2010	763,011	$ 14.76
Granted	214,044	41.94
Lapse of restrictions	(368,738)	16.60
Forfeited	(66,095)	19.74
Non-vested shares outstanding at December 31, 2011	542,222	$ 23.43
Granted	267,377	47.33
Lapse of restrictions	(445,508)	25.82
Forfeited	(34,977)	41.07
Non-vested shares outstanding at December 31, 2012	329,114	$ 37.76

The fair value of awards vested for the year ended December 31, 2012 was $20.8 million. Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2012, 2011 and 2010 was $7.4 million, $4.9 million and $6.1 million, respectively. Unrecognized expense as of December 31, 2012 for all outstanding restricted stock awards was $6.0 million and will be recognized over a weighted average period of 1.25 years.

Performance Share Units

The Company s Compensation Committee of the Board of Directors agreed to allocate a portion of the long-term incentive grants to executives as PSUs. The PSUs are payable, at the Company s option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock at settlement based on the achievement of performance metrics or market conditions at the end of a three-year performance period. The number of shares vested or equivalent cash payment can range from 0% to 200% of the targeted amount as determined by the Compensation Committee. None of these PSUs have voting rights and they may be vested solely at the discretion of the Board of Directors. Any PSUs not vested by the Board at the end of a performance period will expire.

As discussed in Note 2, stock-based compensation expense for PSUs is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the Board s anticipated vesting percentage. For the years ended December 31, 2012, 2011 and 2010, the Company recognized $11.4 million, $23.7 million and $6.8 million, respectively, of stock-based compensation expense associated with PSUs.

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The following table is a summary of PSU awards for the year ended December 31, 2012 assuming a 100% payout of the targeted amount:

	PSUs
Unvested PSUs at December 31, 2011	548,854
Granted	70,010
Vested	(329,048)
Forfeited	(5,509)
Unvested PSUs at December 31, 2012	284,307

On December 31, 2011, the three-year performance period ended for the 2009 PSUs and in the first quarter of 2012, the Company vested the 2009 PSUs at 200% of the targeted amount, or a total of 641,718 units, in a mixture of cash and common stock. Stock-based compensation expense associated with the 2009 PSUs was recognized over the three-year performance period and as of December 31, 2011, the Company had accrued $23.8 million as a component of Accrued liabilities and $4.2 million as a component of Additional paid-in capital.

On December 31, 2012, the three-year performance period ended for the 2010 PSUs and in the first quarter of 2013, the Company vested the 2010 PSUs at 175% of the targeted amount, or a total of 268,469 units, in common stock. Stock-based compensation expense associated with the 2010 PSUs was recognized over the three-year performance period and as of December 31, 2012, the Company had accrued $12.2 million as a component of Additional paid-in capital.

As of December 31, 2012, there were 131,988 unvested PSUs associated with the 2011 and 2012 grants. These awards are accounted for as equity-classified awards and are included as a component of Additional paid-in capital. Based on the Company s closing common stock price of $45.32 at December 31, 2012, and assuming that the Board elects the maximum available payout of 200% for unvested 2011 and 2012 PSUs, unrecognized stock-based compensation expense related to these awards is approximately $9.3 million and would be recognized over the remaining respective performance periods. The Company s total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company s performance, quarter-end closing common stock prices and the Board s anticipated vesting percentage.

(13) Income Taxes

The Company s income tax expense (benefit) consists of the following:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Current:			
Federal	$	$	$ (535)
State		(457)	340
Total		(457)	(195)
Deferred:			
Federal	92,001	52,327	17,739
State	3,903	3,843	9,001
Total	95,904	56,170	26,740
Total income tax expense	$ 95,904	$ 55,713	$ 26,545

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The differences between income taxes computed using the statutory federal income tax rate and that shown in the Consolidated Statement of Operations are summarized as follows:

	Year Ended December 31,					
	2012		2011		2010	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US statutory rate	$ 89,320	35.0%	$ 54,691	35.0%	$ 15,957	35.0%
State income tax, net of federal benefit	1,846	0.7%	3,348	2.2%	2,682	5.9%
Non-deductible permanent items	4,197	1.6%	677	0.4%	1,477	3.2%
Valuation allowance	954	0.4%	(2,262)	(1.4%)	6,558	14.4%
Other, net	(413)	(0.1%)	(741)	(0.5%)	(129)	(0.3)%
Total tax expense	$ 95,904	37.6%	$ 55,713	35.7%	$ 26,545	58.2%

The effective tax rate in all periods is the result of earnings in various domestic tax jurisdictions that apply to a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate due primarily to state taxes, the non-deductibility of certain incentive compensation and a valuation allowance against certain state deferred tax assets. Future effective tax rates could be adversely affected if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities.

The components of deferred tax assets and liabilities are as follows:

	December 31,	
	2012	2011
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 194,259	$ 121,725
Stock-based compensation	3,223	13,347
Accrued bonus and other	4,083	2,957
Gross deferred tax assets	$ 201,565	$ 138,029
Valuation allowance	(5,250)	(4,296)
Net deferred tax assets	$ 196,315	$ 133,733
Deferred tax liabilities:		
Oil and gas properties basis differences	$ (198,734)	$ (47,024)
Derivative financial instruments	(7,356)	(1,544)
Deferred tax liability	$ (206,090)	$ (48,568)
Net deferred tax (liability) asset	$ (9,775)	$ 85,165

The Company generated a federal NOL of $154.5 million for the year ended December 31, 2012, and no current income taxes are expected to be paid. As of December 31, 2012, the total NOL carryforward consists of $565.4 million of federal NOL carryforwards, which expire between 2027 and 2032, and $110.1 million of state NOL carryforwards, which expire primarily between 2014 and 2032. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforward is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Management believes that the Company s taxable temporary differences and future taxable income will more likely than not be sufficient to utilize all of its federal tax carryforwards prior to their expiration.

However, in connection with the asset divestitures in 2010, 2011 and 2012, the Company concluded that it is more likely than not that the NOLs and other deferred tax assets for the states impacted by these divestitures

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will not be realized. Therefore, valuation allowances were established for these items as well as state NOLs in jurisdictions in which the Company previously operated but has since divested of its operating assets. Annually, changes in the Company s valuation allowance are made to reflect revised estimates of the utilization of state deferred tax assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

The rollforward of our deferred tax asset valuation allowance is as follows:

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Balance at the beginning of the year	$ 4,296	$ 6,558	$
Change to provision for income taxes	954	(2,262)	6,558
Balance at the end of the year	$ 5,250	$ 4,296	$ 6,558

Pursuant to authoritative guidance, the Company s $194.3 million deferred tax asset related to NOL carryforwards is net of $9.2 million of unrealized excess tax benefits related to $26.2 million of stock-based compensation which will be recognized in Additional paid-in capital upon utilization of the Company s NOL carryforward.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2012, the Company had no unrecognized tax benefits. The Company files income tax returns in the U.S. and in various state jurisdictions. With few exceptions, the Company is subject to U.S. federal, state and local income tax examinations by tax authorities for tax periods 2005 and forward.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statement of Operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

(14) Earnings Per Share

Basic earnings per share (EPS) is computed by dividing income available to common shareholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if outstanding common stock awards and stock options were exercised at the end of the period.

The following is a calculation of basic and diluted weighted average shares outstanding:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Basic weighted average number of shares outstanding	52,496	51,996	51,381
Dilution effect of stock option and awards at the end of the period	391	620	787
Diluted weighted average number of shares outstanding	52,887	52,616	52,168
Anti-dilutive stock options and awards	1	4	26

(15) Operating Segments

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related

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information. All of the Company s costs are included in one cost pool because all of the Company s operations are located in the United States.

Geographic Area Information

Geographic revenue information below is based on the physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

	Year Ended December 31,		
	2012 (1)	2011 (1)	2010 (1)
Oil, NGL, and Natural Gas Revenue		(In thousands)	
Eagle Ford	$ 561,143	$ 354,741	$ 94,913
South Texas (2)	10,938	48,694	74,569
Other (2)	873	24,102	106,493
Total	$ 572,954	$ 427,537	$ 275,975

(1) Excludes the effects of derivative gains of $40.5 million, $18.7 million and $32.5 million, respectively, for the years ended December 31, 2012, 2011 and 2010.

(2) The decline in revenues was due to the Company s asset divestitures and suspension of capital programs in areas that produced primarily from dry gas reservoirs. See Note 4 Property and Equipment, Net

Major Customers

In 2012, four customers, Enterprise Products Operating LLC, Shell Trading (US) Company, Exxon Mobil Corporation and Calpine Energy Services, accounted for approximately 21%, 21%, 13% and 12%, respectively, of the Company s consolidated revenue, excluding the effects of derivative instruments. The loss of any one of these customers would not have a material adverse effect on the Company s operations as management believes other purchasers are available in the Company s areas of operations.

In 2011, four customers, Shell Trading (US) Company, Calpine Energy Services, Regency Gas Services, LLC, and Exxon Mobil Corporation, accounted for approximately 25%, 24%, 17% and 10%, respectively, of the Company s consolidated revenue, excluding the effects of derivative instruments.

In 2010, two customers, Calpine Energy Services and Shell Trading (US) Company, accounted for approximately 48% and 16%, respectively, of consolidated revenue, excluding the effects of derivative instruments.

(16) Guarantor Subsidiaries

The Company s Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several, and the subsidiaries of Rosetta Resources Inc., other than the subsidiary guarantors, are minor. In addition, there are no restrictions on the ability of Rosetta Resources Inc. to obtain funds from its subsidiaries by dividend or loan. Finally, none of Rosetta Resources Inc. s subsidiaries has restricted assets that exceed 25% of the net assets of Rosetta Resources Inc. as of December 31, 2012 which may not be transferred to the parent company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

Supplemental Oil and Gas Disclosures

(Unaudited)

The following disclosures for the Company are made in accordance with authoritative guidance regarding disclosures about oil and natural gas producing activities. Users of this information should be aware that the

process of estimating quantities of proved, proved developed and proved undeveloped crude oil, NGL and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves are those quantities of oil, NGL and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

Proved developed reserves are proved reserves that can be expected to be recovered (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved undeveloped reserves are reserves that are 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Estimates of proved developed and proved undeveloped reserves as of December 31, 2012 are based on estimates made by the Company s engineers and audited by the Company s independent engineers, Netherland, Sewell & Associates, Inc. (NSAI). The Company s primary reserves estimator is the Company s Corporate Engineering Manager, who has 35 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and natural gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Company makes representations to the independent engineers that it has provided all relevant operating data and documents, and in turn the Company reviews these reserve reports provided by the independent engineers to ensure completeness and accuracy. NSAI performs petroleum engineering consulting services under the Texas Board of Professional Engineers. NSAI s President and Chief Operating Officer is a licensed professional engineer with more than 30 years of experience and the engineer and geologist charged with the Company s audit are both licensed professionals with more than 50 years of experience combined.

The preparation of our reserve estimates are completed in accordance with the Company s prescribed internal control procedures, which include verification of input data into a reserve forecasting and economic

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evaluation software, as well as management review. The technical persons responsible for preparing the reserve estimates meet the required standards regarding qualifications and objectivity. Additionally, the Company engages qualified, independent reservoir engineers to audit the internally generated reserve report in accordance with all SEC reserve estimation guidelines.

A twelve-month first-day-of-the-month historical average price as of December 31, 2012, 2011 and 2010 was used for future sales of oil and natural gas. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of proved oil, NGL and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in oil, NGL and natural gas prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

Capitalized Costs Relating to Oil, NGL and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company s oil, NGL and natural gas producing activities at December 31, 2012, 2011 and 2010:

	2012	2011	2010
		(In thousands)	
Proved properties	$ 2,829,431	$ 2,297,312	$ 2,124,615
Unproved properties	95,540	141,016	91,148
Total	2,924,971	2,438,328	2,215,763
Less: Accumulated depletion	(1,797,203)	(1,649,403)	(1,530,799)
Net capitalized costs	$ 1,127,768	$ 788,925	$ 684,964

Net capitalized costs include asset retirement costs of $15.1 million, $18.0 million and $24.8 million as of December 31, 2012, 2011 and 2010, respectively.

Costs Incurred in Oil, NGL and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company s oil, NGL and natural gas producing activities for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Acquisition costs of properties			
Proved	$	$	$ 28,445
Unproved	18,753	10,605	26,658
Subtotal	18,753	10,605	55,103
Exploration costs	93,542	98,781	49,108
Development costs	531,957	369,865	233,184
Total	$ 644,252	$ 479,251	$ 337,395

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Results of Operations for Oil, NGL and Natural Gas Producing Activities

	Year Ended December 31,		
	2012 (1)	2011 (1)	2010 (1)
		(In thousands)	
Oil, NGL and natural gas producing revenues	$ 572,954	$ 427,537	$ 275,975
Production costs	110,977	69,289	64,001
Depreciation, depletion and amortization	154,223	123,244	116,558
Income before income taxes	307,754	235,004	95,416
Income tax provision	115,716	83,896	55,555
Results of operations	$ 192,038	$ 151,108	$ 39,861

(1) Excludes the effects of derivative gains of $40.5 million, $18.7 million and $32.5 million, respectively, for the years ended December 31, 2012, 2011 and 2010.

The results of operations for oil and natural gas producing activities exclude other income and expenses, interest charges and general and administrative expenses. Sales are based on market prices.

Net Proved and Proved Developed Reserve Summary

The following table provides a rollforward of the total proved reserves (all within the United States) for the years ended December 31, 2012, 2011 and 2010, respectively, as well as proved developed and proved undeveloped reserves at the end of each respective year.

	Oil (MBbl) (1)	Natural gas liquids (MBbl)	Natural gas (MMcf)	Equivalents (MBoe)
Net proved reserves at December 31, 2009	3,825	5,221	296,769	58,488
Revisions of previous estimates (2)	347	497	(54,059)	(8,208)
Purchases in place	561	887	8,732	2,903
Extensions, discoveries and other additions (3)	9,321	14,139	132,195	45,492
Sales in place	(915)	(322)	(55,500)	(10,487)
Production	(738)	(1,096)	(39,210)	(8,369)
Net proved reserves at December 31, 2010	12,401	19,326	288,927	79,819
Revisions of previous estimates (4)	4,839	7,192	60,712	22,212
Purchases in place				
Extensions, discoveries and other additions (5)	21,027	26,344	210,292	82,420
Sales in place	(34)		(80,582)	(13,464)
Production	(1,863)	(2,643)	(33,393)	(10,072)
Net proved reserves at December 31, 2011	36,370	50,219	445,956	160,915
Revisions of previous estimates (6)	(4,947)	4,923	(10,107)	(1,709)
Purchases in place	70	104	744	298
Extensions, discoveries and other additions (7)	16,737	22,440	158,788	65,641
Sales in place	(309)	(1,641)	(52,075)	(10,629)

Production	(3,497)	(4,472)	(33,853)	(13,611)
Net proved reserves at December 31, 2012	44,424	71,573	509,453	200,905

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	Oil (MBbl) (1)	Natural gas liquids (MBbl)	Natural gas (MMcf)	Equivalents (MBoe)
Proved Developed Reserves				
December 31, 2009	2,324	2,345	236,613	44,104
December 31, 2010	3,687	6,471	183,954	40,817
December 31, 2011	11,766	16,635	177,278	57,947
December 31, 2012	19,321	25,068	178,214	74,092
Proved Undeveloped Reserves				
December 31, 2009	1,501	2,876	60,156	14,384
December 31, 2010	8,714	12,855	104,973	39,002
December 31, 2011	24,604	33,584	268,678	102,968
December 31, 2012	25,103	46,505	331,239	126,813

(1) Includes crude oil and condensate.
(2) Upward revision of 1,849 MBoe due to twelve-month first-day-of-the-month historical average commodity prices. Downward revision of 10,057 MBoe primarily due to reducing proved undeveloped reserves (PUDs) in the South Texas Lobo trend and in the Sacramento Basin trend as these reserves were not scheduled to be developed within five years.
(3) The Company added 43,205 MBoe in the Eagle Ford area by drilling and completing 18 wells and adding 49 proved undeveloped locations. The Company also added 2,287 MBoe primarily by drilling and completing 62 wells in the DJ Basin.
(4) Upward revision of 22,212 MBoe resulting from positive performance revisions primarily due to an increase in the estimated ultimate recovery of hydrocarbons on 35 Gates Ranch wells. Twenty-two of these Gates Ranch wells have greater than 12 months of production history and some of these wells have been producing for over two years. The decline profiles on wells with significant production history indicate that the estimated ultimate recovery is much more likely to increase or remain constant than to decline.
(5) The Company added 82,420 MBoe in the Eagle Ford area by drilling and completing 13 wells and adding 91 proved undeveloped locations.
(6) The downward revision of 1,709 MBoe was primarily due to two factors in the Eagle Ford area. The first factor was a downward oil revision of 4,947 MBbl, partially offset by an upward NGL revision of 4,923 MBbl, which was due to condensate stabilization that is required before transportation of condensate to the market. The stabilization process separates NGLs from our oil production which resulted in a reclassification of some of our reserves from oil to NGLs. The second factor was a downward natural gas revision of 10,107 MMcf, which was due largely to a decrease in the twelve-month first-day-of-the-month historical average commodity price for natural gas from $4.12 per MMBtu in 2011 to $2.76 per MMBtu in 2012 and an increase in treating and transportation costs.
(7) The Company added 65,641 MBoe primarily in the Eagle Ford area by drilling and completing 37 wells and adding 54 proved undeveloped locations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, NGL and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by authoritative guidance and based on oil, NGL and natural gas reserves and production volumes estimated by internal reserves engineers and audited by independent petroleum engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. In accordance with SEC requirements, the estimated discounted future net revenues from proved reserves are generally based on average first-day-of-the-month oil and natural gas prices in effect for the prior twelve months in 2012, 2011 and 2010 and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs are as of the date of the estimate. Further, information contained in the following table

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should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company s oil and natural gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of oil, NGL and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and natural gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company s reserves for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31, 2012		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 3,239	$ 5,013	$ 8,252
Future production costs	(854)	(1,227)	(2,081)
Future development costs	(8)	(1,110)	(1,118)
Future income taxes	(652)	(733)	(1,385)
Future net cash flows	1,725	1,943	3,668
Discount to present value at 10% annual rate	(859)	(968)	(1,827)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$ 866	$ 975	$ 1,841

	Year Ended December 31, 2011		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 2,527	$ 4,765	$ 7,292
Future production costs	(542)	(816)	(1,358)
Future development costs	(18)	(990)	(1,008)
Future income taxes	(584)	(878)	(1,462)
Future net cash flows	1,383	2,081	3,464
Discount to present value at 10% annual rate	(702)	(1,056)	(1,758)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$ 681	$ 1,025	$ 1,706

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	Year Ended December 31, 2010		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 1,351	$ 1,638	$ 2,989
Future production costs	(471)	(235)	(706)
Future development costs	(23)	(493)	(516)
Future income taxes	(165)	(175)	(340)
Future net cash flows	692	735	1,427
Discount to present value at 10% annual rate	(453)	(277)	(730)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$ 239	$ 458	$ 697

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31		
	2012	2011 (in millions)	2010
Standardized measure - beginning of year	$ 1,706	$ 697	$ 465
Sales and transfers of crude oil, NGLs and natural gas produced, net of production costs	(462)	(358)	(212)
Revisions to estimates of proved reserves:			
Net changes in prices and production costs	(591)	39	126
Extensions, discoveries, additions and improved recovery, net of related costs	814	1,117	495
Development costs incurred	220	370	219
Changes in estimated future development costs	54	(26)	(91)
Revisions of previous quantity estimates	(12)	357	(95)
Accretion of discount	229	143	47
Net change in income taxes	(17)	(549)	(206)
Purchases of reserve in place	6		33
Sales of reserves in place	(104)	(79)	(83)
Changes in timing and other	(2)	(5)	(1)
Standardized measure - end of year	$ 1,841	$ 1,706	$ 697

Quarterly Selected Financial Data

(Unaudited)

Summaries of the Company s results of operations by quarter for the years ended 2012 and 2011 are as follows:

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			

Revenues	$ 114,458	$ 197,981	$ 122,752	$ 178,308
Operating income	40,541	127,111	33,442	78,474
Net income	22,297	76,969	17,689	42,340
Basic earnings per share	0.43	1.47	0.34	0.81
Diluted earnings per share	0.42	1.46	0.33	0.80

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	2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 97,071	$ 111,557	$ 101,257	$ 136,315
Operating income	22,345	45,037	55,114	55,915
Net income (1)	10,997	25,400	31,948	32,201
Basic earnings per share	0.21	0.49	0.61	0.62
Diluted earnings per share	0.21	0.48	0.61	0.61

(1) Certain items were identified and corrected within the fourth quarter of 2011. The corrections did not have a significant impact on any prior interim or annual periods.

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act), as of December 31, 2012. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2012, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management s Annual Report on Internal Control Over Financial Reporting

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a 15(f). Management conducted an assessment as of December 31, 2012 of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2012, based on criteria in *Internal Control Integrated Framework* issued by the COSO.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Name	**Age as of February 26, 2013**	**Position**
Randy L. Limbacher	54	Chairman, Chief Executive Officer and President
John E. Hagale	56	Executive Vice President and Chief Financial Officer
John D. Clayton	49	Senior Vice President, Asset Development
James E. Craddock	54	Senior Vice President, Drilling and Production Operations
J. Chad Driskill	48	Vice President, Marketing and Business Development
Gerald L. Maxwell	59	Vice President, Human Resources & Administration
Don O. McCormack	51	Vice President, Treasurer and Chief Accounting Officer

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On February 26, 2013, the Company announced certain changes in the leadership of the Company. Effective at the close of business on February 26, 2013, Randy L. Limbacher is resigning as Chairman, Chief Executive Officer and President of the Company. Mr. Limbacher will be succeeded as Chairman, Chief Executive Officer and President by James E. Craddock. In addition, John D. Clayton was appointed as Executive Vice President and Chief Operating Officer of the Company. Mr. Limbacher will remain with the Company until April 2013 to provide transitional support for the change in leadership at the Company.

The remaining information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the headings Security Ownership of Directors and Executive Officers, Company Nominees for Director, Section 16(a) Beneficial Ownership Reporting Compliance, and Corporate Governance and Committees of the Board.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the headings Security Ownership of Directors and Executive Officers, Company Nominees for Director, Section 16(a) Beneficial Ownership Reporting Compliance, and Corporate Governance and Committees of the Board.

Item 11. Executive Compensation

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the headings Executive Compensation, Information Concerning the Board of Directors, and Compensation Committee Report.

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

This information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the headings Security Ownership of Certain Beneficial Owners and Management and Securities Authorized for Issuance Under Equity Compensation Plans.

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

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the heading Certain Transactions and Corporate Governance and Committees of the Board.

Item 14. Principal Accountant Fees and Services

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2013 annual meeting under the heading Audit and Non-Audit Fees Summary.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

a. The following documents are filed as a part of this report or incorporated herein by reference:

(1) Our audited Consolidated Financial Statements are provided in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(2) Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(3) Exhibits: The following documents are included as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed on December 6, 2012 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.3	Form of the 9.500% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 of the Company s Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
10.9	Amended and Restated 2005 Long-Term Incentive Plan, effective January 1, 2011 (incorporated herein by reference to Exhibit 10.9 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.10	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.18	

	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company s Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).

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10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.31	Amended and Restated Employment Agreement with Randy L. Limbacher (incorporated herein by reference to Exhibit 10.31 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.36	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.37	Amended and Restated Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.37 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.39 *	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement attached hereto as Exhibit 10.39.
10.40	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.40 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.41	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).

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10.42	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.42 to the Company s Annual Report on Form 10-K filed on February 26, 2010 (Registration No. 000-51801)).
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company s Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.46	Second Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.48	Third Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.48 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.50	Fourth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of May 10, 2011, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
10.51	Fifth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 25, 2012, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.51 to the Company s Current Report on Form 8-K filed on April 30, 2012 (Registration No. 000-51801)).
21.1*	Subsidiaries of the registrant
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Periodic Financial Reports by Randy L. Limbacher in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Periodic Financial Reports by John E. Hagale in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Periodic Financial Reports by Randy L. Limbacher and John E. Hagale in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith

Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 26, 2013.

ROSETTA RESOURCES INC.

By: /s/ Randy L. Limbacher
Randy L. Limbacher, Chairman of the Board,

Chief Executive Officer and President

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 capacity and on the dates indicated:

Signature	Title	Date
/s/ Randy L. Limbacher Randy L. Limbacher	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)	February 26, 2013
/s/ John E. Hagale John E. Hagale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2013
/s/ Don O. McCormack Don O. McCormack	Vice President, Treasurer and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2013
/s/ Philip L. Frederickson Philip L. Frederickson	Lead Director	February 26, 2013
/s/ Richard W. Beckler Richard W. Beckler	Director	February 26, 2013
/s/ Matthew D. Fitzgerald Matthew D. Fitzgerald	Director	February 26, 2013
/s/ D. Henry Houston	Director	February 26, 2013

D. Henry Houston		
/s/ Carin S. Knickel	Director	February 26, 2013
Carin S. Knickel		
/s/ Donald D. Patteson, Jr.	Director	February 26, 2013
Donald D. Patteson, Jr.		

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Glossary of Oil and Natural Gas Terms

We are in the business of exploring for and producing oil, NGLs and natural gas. Oil, NGL and natural gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and natural gas industry. The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

3-D Seismic. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional seismic data.

Amplitude. The difference between the maximum displacement of a seismic wave and the point of no displacement, or the null point.

(Amplitude plays) anomalies. An abrupt increase in seismic amplitude that can in some instances indicate the presence of hydrocarbons.

Analogous reservoir. Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest; (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

Anticline. An arch-shaped fold in rock in which layers are upwardly convex, often forming a hydrocarbon trap. Anticlines may form hydrocarbon traps, particularly in folds with reservoir-quality rocks in their core and impermeable seals in the outer layers of the fold.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Behind Pipe Pays. Reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Boe. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil, NGLs or natural gas.

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed oil, NGL and natural gas reserves. Developed oil, NGL and natural gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Economically producible. The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and natural gas producing activities.

Estimated ultimate recovery. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. Optimizing oil, NGL and natural gas production from producing properties or establishing additional reserves in producing areas through additional drilling or the application of new technology.

Exploratory well. A well drilled to find and produce oil, NGL or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil, NGLs or natural gas in another reservoir or to extend a known reservoir.

Fault. A break or planar surface in brittle rock across which there is observable displacement.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development costs. Capital costs incurred in the acquisition, exploration, development and revisions of proved oil and natural gas reserves divided by proved reserve additions.

Fracking or fracture stimulation technology. The technique of improving a well s production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand, ceramics or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

Gas. Natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well that has the ability to produce higher volumes than a vertical well drilled in the same formation.

Hydraulic Fracturing. See *Fracking or fracture stimulation technology* above.

Hydrocarbon indicator. A type of seismic amplitude anomaly, seismic event, or characteristic of seismic data that can occur in a hydrocarbon-bearing reservoir.

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Infill well. A well drilled between known producing wells to better exploit the reservoir.

Injection well or injection. A well which is used to place liquids or natural gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Lease operating expenses. The expenses of lifting oil, NGLs or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of oil, condensate or NGLs.

MBoe/d. One thousand barrels of crude oil equivalent per day.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of oil, condensate or NGLs.

MMBoe/d. One million barrels of crude oil equivalent per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Nonoperated working interests. The working interest or fraction thereof in a lease or unit, the owner of which is without operating rights by reason of an operating agreement.

NYMEX. New York Mercantile Exchange.

Operated working interests. Where the working interests for a property are co-owned, and where more than one party elects to participate in the development of a lease or unit, there is an operator designated for full control of all operations within the limits of the operating agreement for the development and production of the wells on the co-owned interests. The working interests of the operating party become the operated working interests.

Pay. A reservoir or portion of a reservoir that contains economically producible hydrocarbons. The overall interval in which pay sections occur is the gross pay; the smaller portions of the gross pay that meet local criteria for pay (such as a minimum porosity, permeability and hydrocarbon saturation) are net pay.

Payout. Generally refers to the recovery by the incurring party of its costs of drilling, completing, equipping and operating a well before another party s participation in the benefits of the well commences or is increased to a new level.

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Permeability. The ability, or measurement of a rock s ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily are described as permeable and tend to have many large, well-connected pores.

Porosity. The percentage of pore volume or void space, or that volume within rock that can contain fluids.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil, NGL and natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission s practice, to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved oil, NGL and natural gas reserves or Proved reserves. Proved oil, NGL and natural gas reserves are those quantities of oil, NGL and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil, NGL and natural gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole,

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the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the twelve-month first day of the month historical average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

***Proved undeveloped reserves*.** Proved undeveloped oil, NGL and natural gas reserves are reserves that are 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 are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

***Proved reserve additions*.** The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

***Reasonable certainty*.** If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

***Reliable technology*.** Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

***Reserves*.** Reserves are estimated remaining quantities of oil, NGLs and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil, NGLs and natural gas or related substances to market and all permits and financing required to implement the project.

***Reserve additions*.** Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life index. This index is calculated by dividing year-end reserves by the average production during the past year to estimate the number of years of remaining production.

Reserve replacement cost. This metric provides an assessment of the cost of adding reserves that is ultimately included in depreciation, depletion and amortization expense. The metric is calculated by dividing capital costs incurred in the current year to add proved reserves (excluding other or corporate capital expenditures) by the sum of current year reserve extensions, discoveries and other additions, reserve revisions of previous estimates and reserve purchases in place.

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Reservoir**.** A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources**.** Resources are quantities of oil, NGLs and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

Secondary recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Natural gas injection and waterflooding are examples of this technique.

Stratigraphy. The study of the history, composition, relative ages and distribution of layers of the earth s crust.

Stratigraphic trap. A sealed geologic container capable of retaining hydrocarbons that was formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

Trap. A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not escape.

Unconventional resource. A term used in the oil and natural gas industry to refer to a play in which the targeted reservoirs generally fall into one of four categories: (1) tight sands, (2) coal beds, (3) gas shales, or (4) oil shales. These reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether or not such acreage contains proved reserves.

Undeveloped oil, NGL and natural gas reserves or Undeveloped reserves**.** Undeveloped oil, NGL and natural gas reserves are reserves of any category that are 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Workover. The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

Workover rig. A portable rig used to repair or adjust downhole equipment on an existing well.

/d. Per day when used with volumetric units or dollars.