FOREST OIL CORP
Form 10-K
February 22, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)

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

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission File Number: 1-13515

FOREST OIL CORPORATION
(Exact name of registrant as specified in its charter)

State of incorporation: New York	I.R.S. Employer Identification No. 25-0484900
707 17th Street, Suite 3600, Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (303) 812-1400
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $.10 Per Share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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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 o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o 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 o
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 o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
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 o	Non-accelerated filer o (Do not check if a smaller	Smaller reporting company o

reporting company)

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, was $857,155,481 (based on the closing price of such stock).

There were 119,353,202 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 19, 2013.

Documents incorporated by reference: Portions of the registrant's notice of annual meeting of shareholders and proxy statement to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end of December 31, 2012 are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

Throughout this Annual Report on Form 10-K, we use the terms "Forest," "Company," "we," "our," and "us" to refer to Forest Oil Corporation and its subsidiaries. In the following discussion, we make statements that may be deemed "forward-looking" statements within the meaning of 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"). See "Forward-Looking Statements," below, for more details. We also use a number of terms used in the oil and gas industry. See "Glossary of Oil and Gas Terms" for the definition of certain terms.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids ("NGL") primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest's total estimated proved oil and gas reserves as of December 31, 2012 were approximately 1,363 Bcfe, all of which are located in the United States.

Strategy

Forest's long-term operating strategy strives to increase shareholder value through the achievement of economic growth by developing our core operational areas located in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area. In addition, our growth may be supplemented from time to time through opportunistic acquisitions. We endeavor to execute this strategy as follows:

Exploit and develop our oil and gas assets for economic growth while maintaining a capital expenditure budget that approximates cash flows from operating activities. In our efforts to build shareholder value, we plan to continue to apply advanced drilling and completion technologies when developing our oil and gas assets, including horizontal drilling and multi-stage hydraulic fracture stimulation techniques. We believe these technologies are critical to our efforts to provide capital-efficient growth from our diverse portfolio of shale, unconventional, and conventional oil and natural gas properties. Our core operational areas have a large number of commodity-diverse drilling locations identified. In 2012, due to a low natural gas price environment, we devoted the majority of our capital expenditures to oil and natural gas liquids projects, including approximately 40% in the Texas Panhandle Area and 30% in the Eagle Ford Shale. We developed our original 2012 capital expenditure budget using natural gas pricing assumptions that were higher than the actual prices we realized during 2012. As a result, our capital expenditures exceeded cash flows in 2012. However, we meaningfully reduced our drilling program from nine rigs to five rigs in the second half of 2012 and our capital expenditures now more closely approximate our cash flows. In 2013, we expect to maintain our capital expenditures within a reasonable range of our expected cash flows based on the current commodity price environment.

As the graph below depicts (see "Recent Trends and 2013 Outlook"), natural gas prices have become substantially disconnected from oil prices and trade significantly below the energy-equivalent conversion of six Mcf "equivalents" per barrel of oil or natural gas liquids. For example, during 2012, the average of the first-day-of-the-month NYMEX gas price was $2.76 per Mcf, and the average of the first-day-of-the-month NYMEX oil price was $94.79 per barrel. Based on these prices, if a price-equivalent conversion was used, the conversion factor would be approximately 34 Mcf per barrel of oil and approximately 16 Mcf per barrel of NGLs. Over the last ten years, this price-equivalent ratio has averaged approximately 15 Mcf per barrel of oil and approximately 7.5 Mcf per barrel of NGLs. While our total net sales volumes declined in 2012 as compared to 2011 using the energy-equivalent ratio, our 2012 net sales volumes have grown in excess of 3% compared to 2011 using the more relevant ten-year average price-equivalent conversion factor.

Focus on operational control, cost efficiencies, and high-margin projects. Our development efforts are focused in areas where we have concentrated land positions, a large drilling inventory, and operational control,

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which allow us to optimize our development plans and, therefore, reduce costs. Furthermore, our portfolio of drilling opportunities provides us with the flexibility to allocate capital to projects with the highest margins, which currently include oil or natural gas liquids drilling projects. In addition, focusing on areas in which we have operational control allows us to control the timing of our development efforts and capital spending.

Rationalize our asset base through property divestitures and acquisitions. In the near term, as economic conditions permit, we may divest certain non-core assets, focusing primarily on non-producing, non-reserve based assets that are not located in our three core operational areas of the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area. Over the longer term, we intend to pursue property acquisitions to enhance existing business operations in our core operational areas.

Maintain financial flexibility. We intend to maintain a strong liquidity position to successfully execute our long-term operating strategy through the application of budget controls and prudent financial management. Further, we intend to focus on maintaining or reducing our debt at levels relative to our estimated proved reserves and EBITDA, and, if needed, we may consider divestitures to increase our financial flexibility. In addition, we may consider other avenues, such as farm-ins or joint development partnerships, as a way to increase our ability to accelerate development opportunities.

Recent Trends and 2013 Outlook

The market prices for oil, natural gas, and NGLs, which have been extremely volatile in recent years, have a significant impact on our financial results and also influence, among other things, where we direct our capital expenditures, the amount of our capital expenditures, and the quantity and duration of our hedging program, which is designed to lessen our exposure to fluctuations in commodity prices. Beginning in the second half of 2008, the market prices for oil, natural gas, and NGLs declined dramatically as a result of the global economic crisis. As the graph below depicts, while the average prices we received for our oil, and to a lesser extent for our NGLs, have improved since 2009, natural gas prices have continued to lag due to North American supply and demand fundamentals. In 2012, the market price for natural gas reached a ten-year low primarily due to an abnormally warm winter, which significantly reduced demand. While prices have improved since mid-2012, we are not planning on natural gas prices to materially improve from current levels in 2013. With this view, we have hedged all of our forecasted 2013 natural gas production at approximately $4.00 per MMBtu. In addition, in 2013 we plan to continue to direct the majority of our exploration and development capital expenditures to oil and NGL rich prospects within our core development areas discussed below.

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Core Operational Areas

Our core operational areas consist of a balanced portfolio of tight-gas sands and shale plays with multiple stacked-pay opportunities that have exposure to oil, natural gas, and natural gas liquids. Our primary areas of focus in 2013 will be in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area.

Texas Panhandle Area

We have approximately 100,000 net acres in the Texas Panhandle Area, establishing Forest as one of the top acreage holders in this area. The area provides us with horizontal drilling opportunities targeting multiple oil formations such as the Missourian Wash (Hogshooter), Tonkawa, Douglas, and Cleveland as well as several liquids-rich intervals in the Granite Wash formation. We drilled our first horizontal wells targeting the Granite Wash formation in 2009, leveraging our vertical delineation database of over 600 wells to determine the most prospective intervals to initiate a horizontal drilling campaign. Based on success achieved in 2009, we began a horizontal development program targeting other productive formations in the Texas Panhandle and now have successfully completed horizontal wells in 16 distinct formations, including seven zones that have been identified as prospective for oil development. During 2012, we primarily focused on developing our oil opportunities, including the Missourian Wash Hogshooter interval. We have drilled eight Missourian Wash Hogshooter wells since initiating our drilling program in 2011 that have had a 30-day average gross production rate of 1,820 Boe/d (67% oil) and a 90-day average gross production rate of 1,200 Boe/d (64% oil). In 2013, we plan to operate a two rig drilling program targeting primarily the Missourian Wash Hogshooter, Tonkawa, Douglas, and other oil intervals.

Eagle Ford Shale

We have approximately 86,000 net acres in the Eagle Ford Shale, primarily located in Gonzales County in South Texas. We commenced the drilling of our first horizontal well in the Eagle Ford Shale at the end of 2010 and expanded the program in 2011 to focus on the optimization of our development operations. Currently, our drilling in the Eagle Ford Shale is focused in the central fairway of our acreage position, where we have experienced the most consistent results and have the largest, most contiguous block of acreage. We have initiated a development plan that employs a one to two rig drilling program in the area, which should allow us to hold approximately 40,000 acres over the next several years. We have identified approximately 500 total locations on this acreage position based on 80-acre spacing. In an effort to increase drilling efficiencies and generate higher rates of return while reducing well costs, we recently equipped one of our drilling rigs with a “rig-walking” system that will allow for multi-well pad drilling. We drilled 14 wells in the central fairway of the Eagle Ford Shale during 2012 that had a 30-day average gross production rate of 490 Boe/d (94% oil) and 13 of the wells had a 90-day average gross production rate of 353 Boe/d (94% oil). Average net sales from the Eagle Ford Shale approximated 1,600 Boe/d in 2012, a 132% increase over 2011 average net sales volumes. In 2013, we plan to maintain a one to two rig drilling program in the Eagle Ford Shale.

East Texas / North Louisiana Area

We have approximately 123,000 net acres in the East Texas / North Louisiana Area. The area provides for horizontal drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville, and other formations. Our development program was initially focused on natural gas in the Haynesville Shale in North Louisiana, but in 2011 we reduced activity in this area due to the decrease in natural gas prices. During 2012, we changed our focus to liquids-rich drilling projects to take advantage of these higher-margin opportunities. We drilled eight wells targeting the liquids-rich area of the Cotton Valley that had a 30-day average gross production rate of 7.9 MMcfe/d (38% liquids) and seven of the wells had a 90-day average gross production rate of 6.6 MMcfe/d (39% liquids). In 2013, we plan to operate a one rig drilling program in East Texas.

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Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and have generally focused on properties that have substantial development drilling opportunities and undeveloped acreage positions. We also divest non-core assets from time to time to, among other things, upgrade our portfolio, increase our operational efficiencies, and improve financial flexibility.

In January 2013, we entered into an agreement to sell all of our oil and natural gas properties located in South Texas, excluding our Eagle Ford Shale oil properties. This transaction closed on February 15, 2013 and we received net proceeds of $307 million.

In November 2012, we sold all of our oil and natural gas properties located in South Louisiana for net proceeds of $208 million in cash and in October 2012, we sold the majority of our East Texas natural gas gathering assets for net proceeds of $29 million in cash. In conjunction with the natural gas gathering assets sale, we may also earn up to $9 million of additional performance payments contingent on future activity.

In June 2011, we completed an initial public offering of approximately 18% of the common stock of our then wholly-owned subsidiary, Lone Pine Resources Inc. (“Lone Pine”), which held our ownership interests in our Canadian operations. On September 30, 2011, we distributed, or spun-off, our remaining 82% ownership in Lone Pine to our shareholders, by means of a special stock dividend of Lone Pine common shares.

In 2009, we sold oil and natural gas properties located in the Permian Basin in West Texas and New Mexico for net proceeds of $908 million in cash.

In September 2008, we acquired producing oil and natural gas properties located in our Texas Panhandle and East Texas / North Louisiana core areas from Cordillera Texas, L.P. for approximately $570 million in cash and 7.25 million shares of our common stock, valued at approximately $360 million.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2012, all of which are located in the United States, based on the NYMEX Henry Hub (“HH”) price of $2.76 per MMBtu for natural gas and the NYMEX West Texas Intermediate (“WTI”) price of $94.79 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the twelve-month period prior to December 31, 2012. See “Preparation of Reserves Estimates” below and Note 15 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves			
	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Total (MMcfe)(1)
Developed	710,288	12,315	25,518	937,286
Undeveloped	202,545	21,387	15,737	425,289
Total estimated proved reserves	912,833	33,702	41,255	1,362,575

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf “equivalent” per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2012, the average of the first-day-of-the-month gas price was $2.76 per Mcf, and the average of the first-day-of-the-month oil price was $94.79 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 34 Mcf per barrel of oil and approximately 16 Mcf per barrel

of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2012).

As of December 31, 2012, we had estimated proved reserves of 1,363 Bcfe, a decrease of 28% compared to 1,904 Bcfe of estimated proved reserves at December 31, 2011. During 2012, we added 235 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2012 drilling activity in the Texas

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Panhandle Area and the Eagle Ford Shale in South Texas, with such additions offset by property sales of 52 Bcfe and negative revisions of 604 Bcfe. The negative revisions were primarily associated with lower natural gas and natural gas liquids prices, which caused certain natural gas-weighted projects to no longer meet economic investment criteria based on the unweighted arithmetic average of the first-day-of-the-month commodity prices utilized in calculating our reserve estimates. In addition, lower natural gas prices also delayed our initial expected development time frame for drilling certain of our proved undeveloped natural gas locations beyond five years from the time the associated reserves were originally recorded. Accordingly, these proved undeveloped reserves ("PUDs") were reclassified to probable undeveloped reserves in 2012. Also included in the revisions is a reclassification of all 52 Bcfe of our Italian PUDs to probable due to an Italian regional regulatory body's denial of our environmental impact assessment associated with our proposal to commence natural gas production from wells that we drilled and completed in 2007. We are currently appealing the region's denial; however, until the region's denial is reversed or overturned, we determined that we could no longer conclude with reasonable certainty that our Italian natural gas reserves are producible.

As of December 31, 2012, we had estimated proved undeveloped reserves of 425 Bcfe, or 31% of estimated proved reserves, compared to 866 Bcfe, or 45% of estimated proved reserves as of December 31, 2011. The net decrease of 441 Bcfe was primarily due to the negative revisions associated with lower natural gas and natural gas liquids prices and the reclassification to probable of 52 Bcfe of our Italian PUDs, both as discussed above. During 2012, we invested $116 million to convert 45 Bcfe of our December 31, 2011 PUDs to proved developed reserves. The rate at which we convert PUDs to proved developed reserves has been negatively impacted in the last several years due to our transition away from developing natural gas reserves, many of which were reclassified to probable reserves in 2011 and 2012, and towards the development of oil reserves. In connection with this transition, we drilled a high percentage of non-proved locations in an effort to hold leases that would otherwise be lost if instead we were to drill proved undeveloped locations that are on leases already held by producing wells. We expect this trend to continue throughout 2013, after which point we expect to increase our PUD conversion rate. As of December 31, 2012, we have no PUDs that have remained undeveloped for five years or more after they were initially disclosed as PUDs.

Preparation of Reserves Estimates

Reserves estimates included in this Annual Report on Form 10-K are prepared by Forest's internal staff of engineers with significant consultation with internal geologists and geophysicists. The reserves estimates are based on production performance and data acquired remotely or in wells, and are guided by petrophysical, geologic, geophysical, and reservoir engineering models. Access to the database housing reserves information is restricted to select individuals from our engineering department. Moreover, new reserves estimates and significant changes to existing reserves are reviewed and approved by various levels of management, depending on their magnitude. Proved reserves estimates are reviewed and approved by the Senior Vice President, Corporate Engineering and Technology, and at least 80% of our proved reserves, based on net present value, are audited by independent reserve engineers (see "Independent Audit of Reserves" below) prior to review by the Audit Committee. In connection with its review, the Audit Committee meets privately with personnel from DeGolyer and MacNaughton, the independent petroleum engineering firm that audits our reserves, to confirm that DeGolyer and MacNaughton has not identified any concerns or issues relating to the audit and maintains independence. In addition, Forest's internal audit department randomly selects a sample of new reserves estimates or changes made to existing reserves and tests to ensure that they were properly documented and approved.

Forest's Senior Vice President, Corporate Engineering and Technology, who has held this position since January 2013, has 35 years of experience in oil and gas exploration and production and received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines. Prior to January 2013, he held positions of increasing responsibility at Forest since joining the company in 2001, including most recently Vice President, Corporate Engineering, a position in which he was also primarily responsible for overseeing the preparation of reserves estimates. Prior to joining Forest, he held various positions in reservoir engineering and corporate planning with Phillips Petroleum, Midcon Exploration, and Apache Corporation.

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Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil, natural gas liquids, and natural gas that cannot be measured in an exact manner, and the accuracy of any reserves estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, oil, natural gas liquids, and natural gas quantities ultimately recovered will vary from reserves estimates. See Part I, Item 1A "Risk Factors" below for a description of some of the risks and uncertainties associated with our business and reserves.

Independent Audit of Reserves

We engage independent reserve engineers to audit a substantial portion of our reserves. Our audit procedures require the independent engineers to prepare their own estimates of proved reserves for fields comprising at least 80% of the aggregate net present value, discounted at 10% per annum ("NPV"), of our year-end proved reserves for each country in which proved reserves have been recorded. The fields selected for audit also must comprise at least 80% of Forest's fields based on the NPV of such fields and a minimum of 80% of the NPV added during the year through discoveries, extensions, and acquisitions. The procedures prohibit exclusions of any fields, or any part of a field, that comprise part of the top 80%. The independent reserve engineers compare their own estimates to those prepared by Forest. Our audit guidelines require Forest's internal estimates, which are used for financial reporting and disclosure purposes, to be within 5% of the independent reserve engineers' quantity estimates. The independent reserve audit is conducted based on reserve definition and cost and price parameters specified by the Securities and Exchange Commission ("SEC").

For the years ended December 31, 2012, 2011, and 2010, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2012, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 83% of our reserves by NPV as of December 31, 2012. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within 3% of DeGolyer and MacNaughton's aggregate estimate of proved reserves for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists, and has in excess of 38 years of experience in oil and gas reservoir studies and reserves evaluations.

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Drilling Activities

The following table summarizes the number of wells drilled during 2012, 2011, and 2010, all of which are located in the United States, excluding any wells drilled under farmout agreements, royalty interest ownership, or any other wells in which we do not have a working interest. As of December 31, 2012, we had 19 gross (13 net) wells in progress, all of which are located in the United States. During 2012, we drilled a total of 139 gross (77 net) wells, of which 30 were classified as exploratory and 109 were classified as development. Our 2012 drilling program, which primarily consisted of horizontal wells, achieved a 96% success rate.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive(1)	106	49	101	44	75	38
Non-productive(2)	3	1	—	—	5	4
Total development wells	109	50	101	44	80	42
Exploratory wells:						
Productive(1)	27	24	22	21	24	16
Non-productive(2)	3	3	4	3	5	4
Total exploratory wells	30	27	26	24	29	20

(1) A well classified as productive does not always provide economic levels of production.

(2) A non-productive well is a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well; also known as a dry well (or dry hole).

Oil and Natural Gas Wells and Acreage

Productive Wells

The following table summarizes our productive wells as of December 31, 2012, all of which are located in the United States. Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. As of December 31, 2012, we owned interests in 59 gross wells containing multiple completions.

	Gross	Net
Natural Gas	3,554	2,568
Oil	268	140
Total	3,822	2,708

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Acreage

The following table summarizes developed and undeveloped acreage in which we owned a working interest or held an exploration license as of December 31, 2012. A substantial majority of our developed acreage is subject to mortgage liens securing our bank credit facility. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary, as well as acreage related to any options held by us to acquire additional leasehold interests. At December 31, 2012, approximately 20%, 18%, and 13% of our net undeveloped acreage in the United States was held under leases that will expire in 2013, 2014, and 2015, respectively, if not extended by exploration or production activities.

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States(1)	622,184	376,538	621,836	425,372
South Africa(2)	—	—	2,771,695	1,474,542
Italy	—	—	107,043	86,507
Total	622,184	376,538	3,500,574	1,986,421

(1) Concentrations of net acres in the United States as of December 31, 2012 include: 100,000 net acres in the Texas Panhandle Area; 123,000 net acres in the East Texas / North Louisiana Area; 192,000 net acres in South Texas (including 86,000 in the Eagle Ford Shale); 132,000 net acres in the Permian Basin in West Texas; and 74,000 net acres in the Uintah Basin in Utah.

(2) In December 2012, we entered into agreements to dispose of our interests in the Block 2A Production Right and the Block 2C Exploration Right in South Africa. The completion of these transactions is contingent upon the approval of the Minister of Mineral Resources for the government of the Republic of South Africa. At the completion of these transactions, we will no longer hold any acreage in South Africa.

Production, Average Sales Prices, and Production Costs

The following table reflects production, average sales price, and production cost information for the years ended December 31, 2012, 2011, and 2010 for continuing operations. All of our production occurred in the United States for the years presented and we do not have any fields that individually contain 15% or more of our total estimated proved reserves.

	Year Ended December 31,		
	2012	2011	2010
Liquids:			
Oil and condensate:			
Production volumes (MBbls)	3,146	2,491	2,357
Average sales price (per Bbl)	$96.14	$96.22	$76.08
Natural gas liquids:			
Production volumes (MBbls)	3,489	3,154	3,589
Average sales price (per Bbl)	$31.77	$42.91	$34.54
Total liquids:			
Production volumes (MBbls)	6,635	5,645	5,946
Average sales price (per Bbl)	$62.29	$66.43	$51.01
Natural Gas:			
Production volumes (MMcf)	81,008	88,497	101,346
Average sales price (per Mcf)	$2.37	$3.71	$3.99
Total production volumes (MMcfe)[1]	120,818	122,367	137,022
Average sales price (per Mcfe)	$5.01	$5.75	$5.16
Production costs (per Mcfe):			
Lease operating expenses	$.89	$.81	$.67
Transportation and processing costs	.12	.11	.10
Production costs excluding production and property taxes (per Mcfe)	1.02	.92	.77
Production and property taxes	.28	.33	.32
Total production costs (per Mcfe)	$1.30	$1.25	$1.09

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf “equivalent” per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2012, the average of the first-day-of-the-month gas price was $2.76 per Mcf, and the average of the first-day-of-the-month oil price was $94.79 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 34 Mcf per barrel of oil and approximately 16 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2012).

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings or NYMEX WTI monthly averages and is typically sold at the wellhead. Our natural gas liquids production is typically sold under term agreements at prices based on postings at large fractionation facilities. We believe that the loss of one or more of our current oil, natural gas, or natural gas liquids purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. We had no material delivery commitments as of February 21, 2013.

Competition

Forest encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil and gas, obtaining services and labor, and securing drilling rigs and other equipment

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necessary for drilling and completing wells. Our ability to increase reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on major development drilling programs, and acquire additional leases and prospects for future development and exploration. A large number of the companies that we compete with have substantially larger staffs and greater financial and operational resources than we have. Because of the nature of our oil and gas assets and management's experience in exploiting our reserves and acquiring properties, management believes that we effectively compete in our markets.

Industry Regulation

Our oil and gas operations are subject to various national, state, and local laws and regulations in the jurisdictions in which we operate. These laws and regulations may be changed in response to economic or political conditions. Matters subject to current governmental regulation or pending legislative or regulatory changes include bonding or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, taxation, and the use of derivative hedging instruments. Our operations are also subject to permit requirements for the drilling of wells and regulations relating to the location of wells, the method of drilling and the casing of wells, surface use and restoration of properties on which wells are located, and the plugging and abandonment of wells. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may restrict the rates of flow of oil and gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. The laws of the jurisdictions in which we operate regulate, among other things, the production, handling, storage, transportation, and disposal of oil and gas, by-products from oil and gas, and other substances and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. Certain of our operations are conducted on federal land pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed BLM regulations and orders (which are subject to change by the BLM). In addition to permits required from other agencies, lessees must obtain a permit from the BLM prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production, and the removal of facilities. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") imposes reporting and other requirements on our business and operations, including with respect to payments made to U.S. and foreign governments related to our oil and gas exploration and development activities. The legislation also imposes new requirements and oversight on our derivatives transactions, including potential new clearing, margin, and position limits requirements. Significant regulations have been promulgated by the SEC, the Commodity Futures Trading Commission, and other regulatory agencies to implement these requirements and provide certain exemptions for qualified end-users. Although Forest does not anticipate it will be affected differently than other producers of oil and natural gas, the new requirements are likely to impose additional reporting obligations on us with respect to the use of derivative instruments to hedge against commercial risks related to fluctuations in oil and gas commodity prices and interest rates. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. The imposition of these types of requirements or limitations could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities.

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Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, and the courts. We cannot predict when or whether any such proposal, or any additional new legislative or regulatory proposal, may become effective. No material portion of Forest's business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

Environmental and Climate Change Regulation

We are subject to stringent national, state, and local laws and regulations in the jurisdictions where we operate relating to environmental protection, including the manner in which various substances such as wastes generated in connection with oil and gas exploration, production, and transportation operations are managed. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of additional compliance costs, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment, disposal, or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well pluggings or pit closures or other actions of a remedial nature to prevent future contamination.

Our operations produce wastewater that is disposed via injection in underground wells. These wells are regulated under the Safe Drinking Water Act (the "SDWA") and similar state and local laws. The underground injection well program under the SDWA requires permits from the United States Environmental Protection Agency ("EPA") or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, and restricts the types and quantities of fluids that may be injected. We believe that our disposal well operations comply with all applicable requirements under the SDWA and similar state and local laws. However, a change in the regulations or the inability to obtain permits for new injection wells in the future may affect the Company's ability to dispose of produced waters and ultimately increase the cost of the Company's operations.

Hydraulic fracturing is an important process used in the completion of our oil and gas wells. The process involves the injection of water, sand, and chemicals under pressure into low-permeability formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Various state and local governments have implemented or are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, requirements for disclosure of chemical constituents, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For instance, Texas, Colorado, and Louisiana have adopted far-reaching rules that require the public disclosure of chemicals used in the hydraulic fracturing process, with the Texas rules applicable to fracturing treatments on wells with initial drilling permits issued on or after February 1, 2012, and the Colorado rules applicable to fracturing treatments performed on or after April 1, 2012. The Louisiana regulations require operators to disclose all additives used in hydraulic fracturing fluids and the names and concentrations of chemicals subject to Occupational Safety and

Health Administration Hazard Communication requirements that are not deemed a trade secret. The Louisiana requirements are effective for wells with drilling permits issued on or after October 20, 2011. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Several federal entities, including the EPA, also have recently asserted potential

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regulatory authority over hydraulic fracturing, and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with the results of the study anticipated to be available for review in 2014. In addition, Congress has considered legislation that would amend the SDWA to encompass hydraulic fracturing activities. Such a provision would have required hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and record keeping obligations, including disclosure of chemicals used in the fracturing process, and meet plugging and abandonment requirements. If such legislation is adopted in the future, it would establish an additional level of regulation and impose additional costs on our operations. See Part I, Item 1A "Risk Factors—We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations" below.

Nearly half of the states in the U.S., either individually or through multi-state initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases ("GHGs"). Also, the Supreme Court held in Massachusetts, et al. v. EPA (2007) that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act, and subsequently in December 2009, the EPA determined that GHG emissions present an endangerment to public health and the environment because such emissions, according to the EPA, are contributing to warming of the earth's atmosphere and other climate changes. These findings allow the EPA to implement regulations that would restrict GHG emissions under existing provisions of the Clean Air Act. On November 8, 2010, the EPA finalized GHG reporting requirements for the petroleum and natural gas industries. Under this final rule, owners or operators of facilities that contain petroleum and natural gas systems, as defined by the rule, and emit 25,000 metric tons or more of GHGs per year per basin (expressed as carbon dioxide equivalents) will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators will collect emission data, calculate GHG emissions, and follow the specified procedures for quality assurance, missing data, record keeping, and reporting defined in the final rule. For purposes of the rule, an onshore petroleum and natural gas production facility is generally defined as all petroleum and natural gas equipment associated with all petroleum or natural gas production wells and carbon dioxide enhanced oil recovery operations that are under common ownership or control. This includes leased, rented, and contracted activities by an onshore petroleum and natural gas production owner or operator that is located within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists. The rule is estimated to require reporting from approximately 2,800 facilities, covering 85% of the total GHG emissions from the U.S. petroleum and natural gas industries, including all of Forest's facilities, with modeling reporting beginning in late 2012 and actual data reporting beginning in 2013. We expect these new rules to result in increased compliance costs on our operations. In addition, these rules, and any other new rules and regulations addressing GHG emissions, could result in additional operating restrictions.

We believe that it is likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future. We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the United States and other relevant international jurisdictions. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Employees

As of December 31, 2012, we had 605 employees. None of our employees is currently represented by a union for collective bargaining purposes.

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Geographical Data

Forest operates in one industry segment, oil and gas exploration and production, and has one reportable geographical business segment, the United States.

Offices

Our corporate office is located in leased space at 707 17th Street, Denver, Colorado. We maintain an office in Houston, Texas, and also lease or own field offices in the areas in which we conduct operations.

Title to Properties

Title to our oil and gas properties is subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and gas industry. Under the terms of our bank credit facility, we have granted the lenders a lien on the substantial majority of our properties. In addition, our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements, and restrictions, and for current taxes not yet due. Forest's general practice is to conduct a title examination on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to ensure that production from our properties, if obtained, will be salable by Forest.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Annual Report on Form 10-K. Certain definitions, including the definitions of proved developed reserves, proved reserves, and proved undeveloped reserves, have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934. The entire definitions of those terms can be viewed on the SEC's website at http://www.sec.gov.

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

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

Bbtu. One billion British Thermal Units.

Btu. A British Thermal Unit, or the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface temperature and pressure.

Developed acreage. Acreage that is held by producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

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Exploitation. Ordinarily considered to be a form of development within a known reservoir.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location or the undertaking of other work obligations.

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.

Full cost pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration, and development activities are included. Any costs related to production, general and administrative expense, or similar activities are not included.

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

HH or Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the NYMEX.

Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease operating expenses. The expenses of lifting oil or 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, and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

Liquids. Describes oil, condensate, and natural gas liquids.

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

MBoe. Thousand barrels of crude oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMBtu. One million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

NGL or natural gas liquids. Liquid hydrocarbons found in natural gas which may be extracted as separate components, including ethane, propane, butanes, and natural gasoline.

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Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

NYMEX. New York Mercantile Exchange.

Productive wells. Producing wells and wells that are mechanically capable of production.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Quantities of oil and 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 regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the end of the reporting period, 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 or PUDs. Estimated proved 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.

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

Standardized measure or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and property taxes, future capital costs, operating expenses, and estimated future income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's requirements, 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 estimation date in accordance with the SEC's regulations and are held constant for the life of the reserves.

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

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

WTI or West Texas Intermediate. A grade of crude oil used as a benchmark in oil pricing.

Available Information

Forest's website address is http://www.forestoil.com. Available on our website, free of charge, are Forest's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, reports on Forms 3, 4, and 5 filed on behalf of directors and officers, as well as amendments to these reports. These materials are available as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC.

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Also posted on Forest's website, and available in print upon written request of any shareholder addressed to the Secretary of Forest, at 707 17th Street, Suite 3600, Denver, Colorado 80202, are Forest's Corporate Governance Guidelines, the charters for each of the committees of our Board of Directors (including the charters of the Audit Committee, Compensation Committee, and Nominating and Corporate Governance Committee), and codes of ethics for our directors and employees entitled "Code of Business Conduct and Ethics" and "Proper Business Practices Policy," respectively.

Forward-Looking Statements

The information in this Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements are statements other than statements of historical or present facts, that address activities, events, outcomes, and other matters that Forest plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates, or anticipates (and other similar expressions) will, should, or may occur in the future. Generally, the words "expects," "anticipates," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," "may," "will," "could," "should," "future," "potential, negative of such words or other variations of such words, and similar expressions, identify forward-looking statements. Similarly, statements that describe our strategies, initiatives, objectives, plans, or goals are forward-looking. These forward-looking statements are based on our current intent, plans, belief, expectations, estimates, projections, forecasts, and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These statements are not guarantees of future performance.

These forward-looking statements appear in a number of places and include statements with respect to, among other things:

- estimates of our oil and natural gas reserves;
- estimates of our future oil and natural gas production, including estimates of any increases or decreases in our production, and the liquids/natural gas mix of that production;
- our future financial condition and results of operations;
- our future revenues, cash flows, and expenses;
- our access to capital and our anticipated liquidity;
- our future business strategy and other plans and objectives for future operations;
- our outlook on oil and natural gas prices;
- the amount, nature, and timing of future capital expenditures, including future development costs;
- our ability to access the capital markets to fund capital and other expenditures;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States and certain foreign locations where we conduct business operations.

We believe the expectations, estimates, projections, beliefs, forecasts, and assumptions reflected in our forward-looking statements are reasonable, but we can give no assurance that they will prove to be correct. We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are

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difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and gas. See "Competition," "Industry Regulation," and "Environmental and Climate Change Regulation" above, as well as Part I, Item 1A "Risk Factors," Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," and Part II, Item 7A "Quantitative and Qualitative Disclosures about Market Risk" for a description of various, but by no means all, factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information to reflect events or circumstances after the filing of this report with the SEC, except as required by law. All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K and attributable to Forest are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we may make or persons acting on our behalf may issue.

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations. Except where the context otherwise indicates, references to oil and natural gas in this section include natural gas liquids.

Oil and natural gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our results of operations, cash flows, financial condition, access to the capital markets, the economic viability of our reserves, and our ability to reinvest in order to maintain or grow our asset base.

Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to a variety of factors that are beyond our control. Approximately 67% of our estimated proved reserves at December 31, 2012 were natural gas, causing us to be particularly dependent on prices for natural gas.

During the fourth quarter of 2011 and continuing into 2012, natural gas prices declined to ten-year lows. Further deterioration in prices or a continuation of low natural gas prices may mean that it will not be economical to drill or produce natural gas from some of our existing properties, and we may be required to curtail, or stop completely, our production activities in those areas. A continuation of low natural gas prices, or a significant decline in oil prices, may have the following effects on our business:

- impairing our financial condition, liquidity, or ability to fund planned capital expenditures;

- limiting our access to sources of capital, such as equity and debt; or

- prohibiting us from developing our current properties, or from growing our asset base.

We have substantial indebtedness, and we may incur more debt in the future. Our leverage may materially adversely affect our operations and financial condition.

As of December 31, 2012, we had a principal amount of long-term indebtedness of $1.9 billion, including $65 million drawn under our bank credit facility. As of February 21, 2013, we had a principal amount of long-term indebtedness of $1.8 billion with no outstanding borrowings under our bank credit facility.

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Our level of debt may have several important effects on our business and operations; among other things, it may:

- require us to use a significant portion of our cash flows to service the obligations, which could limit our flexibility in planning for and reacting to changes in our business, and reduce the amount available to reinvest in order to maintain or grow our asset base;
- adversely affect the credit ratings assigned by third-party rating agencies, which have in the past and may in the future downgrade their ratings of our debt and other obligations;
- limit our access to the capital markets;
- increase our borrowing costs, and impact the terms, conditions, and restrictions contained in our debt agreements, including the addition of more restrictive covenants;
- place us at a disadvantage compared to companies in our industry that have less debt and other financial obligations; and
- make us more vulnerable to economic downturns, volatile oil, natural gas, and natural gas liquids prices, and adverse developments in our business.

A higher level of debt will increase the risk that we may default on our financial obligations. Our ability to meet our debt obligations and other expenses will depend on our future performance. Our future performance will be affected by oil, natural gas, and natural gas liquids prices, financial, business, domestic, and global economic conditions, governmental regulations and environmental regulations, and other factors, many of which we are unable to control. If our cash flows are not sufficient to service our debt and other obligations or to meet the financial or other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes, we may be required to refinance or restructure the debt, sell assets, or sell shares of our common or preferred equity securities-all on terms that we do not find attractive, if it can be done at all. The governing documents of our debt instruments contain covenants and restrictions that require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness. A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facility or indentures could adversely affect our business and our financial condition and results of operations, and would impact our ability to obtain financing in the future.

We may not be able to obtain funding under our current bank credit facility because of a decrease in our borrowing base or obtain funding in the capital markets on terms we find acceptable.

Historically, we have used our cash flows from operations and borrowings under our bank credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. We currently have a bank credit facility with lender commitments totaling $1.5 billion. The borrowing base is determined by the lenders periodically and is based on the estimated value of our properties using pricing models determined by the lenders at such time. The current borrowing base was set at $900 million following the closing of the sale of our South Texas assets on February 15, 2013. The next scheduled redetermination of the borrowing base will occur on or before May 1, 2013. Also, under the terms of our bank credit facility, our borrowing base will be immediately decreased by an amount equal to 25% of the stated principal amount of senior notes issued in the future (excluding any senior notes that we may issue to refinance senior notes that were outstanding on June 30, 2011). In the future, we may not be able to access adequate funding under our bank credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Since the process for determining the borrowing base under our bank credit facility involves evaluating the estimated value of our oil and natural gas properties using pricing models determined by the lenders at that time, a decline in those prices used may result in a redetermination

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of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

In recent years, volatility in the public and private capital markets has made it more difficult to obtain funding. There is a risk that the cost of obtaining money from the credit markets may increase in the future as lenders and institutional investors may increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity on terms similar to existing debt or at all, or reduce or cease to provide any new funding. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Our debt agreements contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

Our bank credit facility and the indentures governing our senior notes contain restrictive covenants that will limit our ability and the ability of certain of our subsidiaries to, among other things:

- incur or guarantee additional indebtedness or issue preferred shares;
- pay dividends or make other distributions;
- purchase equity interests or redeem subordinated indebtedness early;
- create or incur certain liens;
- enter into transactions with affiliates; and
- sell assets or merge or consolidate with another company.

Complying with the restrictions contained in some of these covenants will require us to meet certain financial ratios and tests, notably with respect to consolidated interest coverage, total assets, net debt, equity, and net income. For example, our bank credit facility provides that we will not permit our ratio of total debt outstanding to EBITDA (as adjusted for non-cash charges) for a trailing 12-month period to be greater than 4.5 to 1.0 at any time. Our ratio of total debt outstanding to EBITDA for the 12-month period ending December 31, 2012, as calculated in accordance with our bank credit facility, was 4.2. Our need to comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, or withstand a future downturn in our business.

We are a relatively small company and therefore may not be able to compete effectively.

Compared to many of the companies in our industry, we are a small company. We face difficulties in competing with the larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. Our limited size can place us at a disadvantage with respect to funding such costs. Our limited size also means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development, or production play can have a disproportionately negative impact on us. Our size can also impair our ability to attract and retain staff and maintain competitive technical capabilities.

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Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

The proved oil and natural gas reserves information and the related future net revenues information included in this Annual Report on Form 10-K and in our other periodic reports represent only estimates, which are prepared by our internal staff of engineers and the majority of which are audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. Estimating quantities of proved oil and natural gas reserves is a complex, inexact process and depends on a number of interpretations of technical data and various factors and assumptions, including assumptions required by the SEC as to oil, natural gas, and natural gas liquids prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. As a result, these estimates are inherently imprecise. Any significant inaccuracies or changes in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the estimated reserves to be significantly different.

At December 31, 2012, approximately 31% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserves estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated.

Our estimated proved reserves as of December 31, 2012 were based on a NYMEX HH price of $2.76 per MMBtu for natural gas and a NYMEX WTI price of $94.79 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the month prices during the twelve-month period prior to December 31, 2012, and an average realization for a barrel of natural gas liquids during that period equal to approximately 36% of the NYMEX WTI price or $33.83. For the year ended December 31, 2011, the comparable prices used to calculate our estimated proved reserves were $4.12 per MMBtu for natural gas, $96.08 per barrel for oil, and an average realization for a barrel of natural gas liquids equal to approximately 46% of the oil price or $44.05. The decline in natural gas and natural gas liquids prices from those used to estimate proved reserves as of December 31, 2011 resulted in 552 Bcfe of downward revisions to our estimated proved reserves during 2012. These revisions were primarily due to proved undeveloped natural gas drilling locations no longer being economic at the lower commodity prices used throughout 2012, including as of December 31, 2012. In addition, lower natural gas prices also delayed our initial expected development time frame for drilling our proved undeveloped natural gas locations beyond five years from the time the wells were originally recorded. Accordingly, these proved undeveloped reserves were reclassified to probable undeveloped reserves in 2012.

You should not assume that any present value of future net cash flows from our estimated proved reserves as set forth in this Annual Report on Form 10-K for the year ended December 31, 2012 represents the market value of our oil and natural gas reserves.

Lower oil, natural gas, and natural gas liquids prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting to report our oil and natural gas activities. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a ceiling limit, which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a ceiling test write-down. Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down does not impact cash flows from operating activities, but it does reduce our shareholders' equity.

Investments in unproved properties are also assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. The amount of impairment assessed, if any, is added to the costs to be amortized,

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or is reported as a period expense, as appropriate. If an impairment of unproved properties is added to the costs to be amortized, the amount by which the ceiling limit exceeds the capitalized costs of proved oil and natural gas properties would be reduced.

We also assess the carrying amount of goodwill in the second quarter of each year and at other periods when events occur that may indicate an impairment exists. These events include, for example, a decline in our market capitalization relative to our net asset values or other adverse economic or qualitative factors.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, natural gas, and natural gas liquids prices are low. In addition, write-downs may occur if we experience downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development or operating costs increase. For example, during 2012 we incurred ceiling test write-downs of $992 million primarily due to a decline in natural gas and natural gas liquids prices used to calculate our estimated proved reserves during 2012. Additional write-downs of the United States cost center may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and natural gas liquids prices used in the calculation of the present value of future net revenue from estimated production of estimated proved reserves decline compared to prices used as of December 31, 2012, unproved property values are impaired, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any, attributable to the cost center.

If we are not able to replace reserves, we will not be able to sustain or grow production.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we replace the reserves we produce through successful development, exploration or acquisition, our proved reserves and production will decline over time.

We do not always find commercially productive reserves through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to determine conclusively prior to drilling a well whether oil or natural gas is present or can be produced economically. Moreover, the costs of drilling, completing, and operating wells are often uncertain. Our drilling activities, therefore, may result in the total loss of our investment or a return on investment significantly below expectation.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

Approximately 53% of our net acreage located in the United States is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. For instance, under our current drilling plans, we will lose our rights under approximately 46,000 of the 86,000 acres in the Eagle Ford Shale that we currently hold. Our drilling plans are subject to change based upon various factors, including drilling results, oil and natural gas prices, cash flow, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.

We deliver the majority of our oil and natural gas through gathering facilities that we do not own or operate. As a result, we are subject to the risk that these facilities may be temporarily unavailable due to mechanical reasons or market conditions, or may not be available to us in the future. If we experience interruptions or loss of pipeline capacity or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our cash flow.

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Drilling is a high-risk activity that could result in substantial losses for us.

We conduct a portion of our drilling activities through a wholly-owned drilling subsidiary that operates drilling rigs and provides services to us and third parties. The activities conducted by the drilling subsidiary are subject to many risks, including well blow-outs, cratering and explosions, pipe failures, fires, uncontrollable flows of oil, natural gas, brine, or well fluids, other environmental hazards, and risks outside of our control, including, among other things, the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources, and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. We maintain insurance against some, but not all, of the risks described above. Generally, pollution related environmental risks are not fully insurable. We do not insure against business interruption. We cannot assure that our insurance will be fully adequate to cover other losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our use of hedging transactions could reduce our cash flow and/or result in reported losses.

We periodically enter into hedging agreements for a portion of our anticipated oil, natural gas, and natural gas liquids production. Our commodity hedging agreements are limited in duration, usually for periods of one year or less; however, we sometimes enter into hedges for longer periods. Should commodity prices increase after we have entered into a hedging transaction, our cash flows will be lower than they would have been without the hedging transaction.

For financial reporting purposes, we do not use hedge accounting, thus we are required to record changes in the fair value of our hedging instruments through our earnings rather than through other comprehensive income had we elected to use hedge accounting. As a consequence, we may report material unrealized losses or gains on our hedging agreements prior to their expiry. The amount of the actual realized losses or gains will differ and will be based on the actual prices of the commodities on the settlement dates as compared to the hedged prices contained in the hedging agreements. As a result, our periodic financial results will be subject to fluctuations related to our derivative instruments.

Moreover, our hedging program may be limited due to certain regulatory constraints. The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted by Congress, among other things, imposes new requirements and oversight on hedging transactions, including new clearing and margin requirements. While certain of the implementing regulations are yet to be finalized by the relevant federal agencies, to the extent that they are applicable to us or our counterparties, we may incur increased costs and cash collateral requirements that could affect our ability to hedge risks associated with our business.

We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations.

Our oil and natural gas operations are subject to various U.S. federal, state, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment. We could incur material costs, including clean-up costs, fines, and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, present or future environmental laws and regulations.

We routinely utilize hydraulic fracturing, which is an important and common practice used to stimulate production of hydrocarbons from tight, or low-permeability formations. State oil and gas commissions typically regulate the process. However, several federal entities, including the EPA, have also recently asserted potential regulatory authority over hydraulic fracturing. Some states, such as Texas, have adopted, and some states, including others in which we operate, are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. Some local governmental bodies have adopted or are considering adopting similar regulations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to operate. Restrictions on, or increased costs of, hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently proposed or finalized rules and guidance imposing more stringent requirements on the oil and gas exploration and production industry could cause us to incur increased capital expenditures and operating costs as well as decrease our levels of production.

On April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks, and other production equipment. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

In addition, federal agencies have recently announced two other regulatory initiatives regarding certain aspects of hydraulic fracturing that could further increase our costs to operate and decrease our levels of production. On May 4, 2012, the U.S. Department of the Interior announced proposed rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. Also on May 4, 2012, the EPA issued draft guidance for federal Safe Drinking Water Act permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. The adoption or implementation of these regulatory initiatives could cause us to incur increased expenditures and decrease our levels of production.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, insurance companies, and their affiliates. These transactions expose us to credit risk in the event of default of our counterparty, principally with respect to hedging agreements but also insurance contracts and bank lending commitments. 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. See Note 9 to the Consolidated Financial Statements included in this Annual Report for a more complete discussion of credit risk with respect to our derivative instruments.

We may face liabilities related to the pending bankruptcy of Pacific Energy Resources, Ltd.

In August 2007, we closed on the sale of our oil and gas assets in Alaska (the "Alaska Assets") to Pacific Energy Resources, Ltd. ("PERL"). In March 2009, PERL filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. PERL requested, and the bankruptcy court has approved, abandonment of PERL's interests in certain of the Alaska Assets. The remaining working interest owners in the Alaska Assets have made the assertion that, in its role as assignor of the Alaska Assets, Forest should be held liable for any contractual obligations of PERL with respect to the Alaska Assets, including obligations related to operating costs and for costs associated with the final plugging and decommissioning of wells and platforms. While we have settled certain litigation relating to the Alaska Assets, litigation relating to decommissioning of the Spurr platform in Cook Inlet remains outstanding.

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Item 1B. Unresolved Staff Comments.

As of December 31, 2012, we did not have any SEC staff comments regarding our periodic or current reports that have been unresolved for 180 days or more.

Item 2. Properties.

Information on Properties is contained in Item 1 of this Annual Report on Form 10-K.

Item 3. Legal Proceedings.

On February 29, 2012, two members of a three-member arbitration panel reached a decision adverse to Forest in the proceeding styled, Forest Oil Corporation, et al. v. El Rucio Land & Cattle Company, Inc., et al., which occurred in Harris County, Texas. The third member of the arbitration panel dissented. The proceeding was initiated in January 2005 and involves claims asserted by the landowner-claimant based on the diminution in value of its land and related damages allegedly resulting from operational and reclamation practices employed by Forest in the 1970s, 1980s, and early 1990s. The arbitration decision awards the claimant $23 million in damages and attorneys' fees and additional injunctive relief regarding future surface-use issues. On October 9, 2012, after vacating a portion of the decision imposing a future bonding requirement on Forest, the trial court for the 55th Judicial District, in the District Court in Harris County, Texas, reduced the arbitration decision to a judgment. Forest is seeking to have this judgment reversed on appeal and believes it has meritorious arguments in support thereof.

On May 25, 2012, a lawsuit, styled Augenbaum v. Lone Pine Resources Inc. et al., was brought as a purported class action in the Supreme Court of the State of New York, New York County against Forest, Lone Pine, certain of Lone Pine's current and former directors and officers (the "Individual Defendants"), and certain underwriters (the "Underwriter Defendants") of Lone Pine's initial public offering (the "IPO"), which was completed on June 1, 2011. The complaint alleges that Lone Pine's registration statement and prospectus issued in connection with the IPO contained untrue statements of material fact or omitted to state material facts relating to forest fires that occurred in Northern Alberta in May 2011, the rupture of a third party oil sales pipeline in Northern Alberta in April 2011, and the impact of those events on Lone Pine, that the alleged misstatements or omissions violated Section 11 of the Securities Act, and that Lone Pine, the Individual Defendants, and the Underwriter Defendants are liable for such violations. The complaint further alleges that the Underwriter Defendants offered and sold Lone Pine's securities in violation of Section 12(a)(2) of the Securities Act, and the putative class members seek rescission of the securities purchased in the IPO that they continue to own and rescissionary damages for securities that they have sold. Finally, the complaint asserts a claim against Forest under Section 15 of the Securities Act, alleging that Forest was a "control person" of Lone Pine at the time of the IPO. The complaint alleges that the putative class, which purchased shares of Lone Pine's common stock pursuant and/or traceable to Lone Pine's registration statement and prospectus, was damaged when the value of the stock declined in August 2011. The complaint does not specify the amount of such damages. Lone Pine has existing obligations to indemnify Forest, the Individual Defendants, and the Underwriter Defendants in connection with the lawsuit. Forest believes that these claims are without merit and intends to defend the claim against it vigorously.

We are a party to various other lawsuits, claims, and proceedings in the ordinary course of business. These proceedings are subject to uncertainties inherent in any litigation, and the outcome of these matters is inherently difficult to predict with any certainty. We believe that the amount of any potential loss associated with these proceedings would not be material to our consolidated financial position; however, in the event of an unfavorable outcome, the potential loss could have an adverse effect on our results of operations and cash flow.

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.

Common Stock

Forest has one class of common shares outstanding, its common stock, par value $.10 per share (“Common Stock”). Forest’s Common Stock is traded on the New York Stock Exchange under the symbol “FST.” On February 21, 2013, our Common Stock was held by 621 holders of record. The number of holders does not include the shareholders for whom shares are held in a “nominee” or “street” name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape, as well as adjusted prices per share of the Common Stock that reflect the stock dividend distributed by Forest on September 30, 2011. There were no cash dividends declared on the Common Stock in 2011 or 2012. On February 21, 2013, the closing price of Forest Common Stock was $6.02.

		Common Stock		Common Stock (As Adjusted)(1)	
		High	Low	High	Low
2011	First Quarter	$40.23	$32.39	$28.56	$22.99
	Second Quarter	38.65	24.56	27.44	17.44
	Third Quarter	28.22	14.14	20.03	10.04
	Fourth Quarter	17.22	8.88	17.22	8.88
2012	First Quarter	$15.15	$11.61	$15.15	$11.61
	Second Quarter	13.69	6.22	13.69	6.22
	Third Quarter	9.32	5.68	9.32	5.68
	Fourth Quarter	9.12	6.06	9.12	6.06

(1) On September 30, 2011, Forest completed the spin-off of Lone Pine by means of a special stock dividend distributed to all shareholders of Forest Common Stock. The stock dividend consisted of .61248511 shares of Lone Pine for each outstanding share of Forest Common Stock. Based on this ratio, the value of the stock dividend to Forest shareholders is deemed by Forest to be equal to $4.18, or the average of the high and low intraday sales prices per share of Lone Pine common stock on September 30, 2011 multiplied by .61248511.

The prices shown in the “As Adjusted” column above for the first through third quarters of 2011 have been adjusted to reflect the stock dividend paid on September 30, 2011. The ratio used for this historical price adjustment is .2901. This represents the ratio of (a) $4.18 to (b) $14.41, the average of the high and low intraday sales prices per share of Forest Common Stock on September 30, 2011.

Dividend Restrictions

Forest’s present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest’s Restated Certificate of Incorporation and Bylaws, (iii) the indentures concerning Forest’s 8½% senior notes due 2014, 7¼% senior notes due 2019, and 7½% senior notes due 2020 and (iv) Forest’s bank credit facility dated as of June 30, 2011. The provisions in the indentures pertaining to these senior notes and in the bank credit facility limit our ability to make restricted payments, which include dividend payments. On March 2, 2006, Forest distributed a special stock dividend in connection with the spin-off of its offshore Gulf of Mexico operations and, as noted above, on September 30, 2011, Forest distributed a special stock dividend in connection with the spin-off of Lone Pine; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends. For further information regarding our

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equity securities, our ability to pay dividends on our Common Stock, and the spin-off of Lone Pine, see Notes 3 and 5 to the Consolidated Financial Statements.

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during the quarter ended December 31, 2012.

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2012. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Forest does not consider this a share buyback program.

Period	Total # of Shares Purchased	Average Price Per Share	Total # of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum # (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
October 2012	1,116	$8.65	—	—
November 2012	6,076	6.29	—	—
December 2012	14,503	6.60	—	—
Fourth Quarter Total	21,695	6.62	—	—

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Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2007 (and the reinvestment of dividends thereafter) in each of Forest Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe that the Dow Jones U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of other similarly-sized energy companies.

*$100 invested on 12/31/07 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

The information in this Annual Report on Form 10-K appearing under the heading “Stock Performance Graph” is being furnished pursuant to Item 201(e) of Regulation S-K and shall not be deemed to be “soliciting material” or “filed” with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act.

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Item 6. Selected Financial Data.

The following table sets forth selected financial and operating data of Forest as of and for each of the years in the five-year period ended December 31, 2012. This data should be read in conjunction with Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto contained elsewhere in this report. We have completed several oil and gas property acquisition and divestiture transactions that affect the comparability of the results for the years presented below. See Part I, Item 1 "Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements for more information on acquisitions and divestitures.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and natural gas liquids sales(1)	$605,523	$703,531	$707,692	$655,579	$1,396,669
Net earnings (loss) from continuing operations	$(1,288,931)	$98,260	$189,662	$(793,789)	$(1,081,446)
Net earnings (loss) from discontinued operations(2)	—	44,569	37,859	(129,344)	55,123
Net earnings (loss)	(1,288,931)	142,829	227,521	(923,133)	(1,026,323)
Less: net earnings attributable to noncontrolling interest(2)	—	4,987	—	—	—
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$(1,288,931)	$137,842	$227,521	$(923,133)	$(1,026,323)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:(3)					
Earnings (loss) from continuing operations	$(11.21)	$.86	$1.68	$(7.61)	$(12.07)
Earnings (loss) from discontinued operations	—	.35	.33	(1.24)	.61
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$(11.21)	$1.21	$2.01	$(8.85)	$(11.46)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:(3)					
Earnings (loss) from continuing operations	$(11.21)	$.85	$1.67	$(7.61)	$(12.07)
Earnings (loss) from discontinued operations	—	.34	.33	(1.24)	.61
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$(11.21)	$1.19	$2.00	$(8.85)	$(11.46)
Total assets(1)	$2,201,862	$3,381,151	$3,070,197	$3,169,054	$4,555,903

Long-term debt[1]	$1,862,100	$1,693,044	$1,869,372	$2,022,514	$2,641,246
Shareholders' (deficit) equity	$(42,824)	$1,193,113	$1,352,787	$1,079,154	$1,672,912
OPERATING DATA[1]					
Annual production:					
Oil (MBbls)	3,146	2,491	2,357	3,397	3,778
Natural gas (MMcf)	81,008	88,497	101,346	116,029	118,120
NGLs (MBbls)	3,489	3,154	3,589	3,012	3,151
Average sales price:					
Oil (per Bbl)	$96.14	$96.22	$76.08	$56.87	$96.85
Natural gas (per Mcf)	$2.37	$3.71	$3.99	$3.33	$7.54
NGLs (per Bbl)	$31.77	$42.91	$34.54	$25.17	$44.54

(1) Amounts reported relate to continuing operations only. See below for more information regarding discontinued operations.

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(2) On June 1, 2011, Forest completed the initial public offering of approximately 18% of the common stock of its then wholly-owned subsidiary, Lone Pine Resources Inc., which held Forest's ownership interests in its Canadian operations. On September 30, 2011, Forest distributed, or spun-off, the remaining 82% of Lone Pine by means of a special stock dividend to Forest's shareholders. Lone Pine's results are reported as discontinued operations throughout this Annual Report on Form 10-K.

(3) In June 2008, the Financial Accounting Standards Board issued authoritative accounting guidance that addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This guidance was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, Forest adopted this guidance as of January 1, 2009. All prior period earnings per share data presented has been adjusted retrospectively to conform to the provisions of this guidance.

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

All expectations, forecasts, assumptions, and beliefs about our future financial results, condition, operations, strategic plans, and performance are forward-looking statements, as described in more detail in Part I, Item 1 under the heading "Forward-Looking Statements." Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A "Risk Factors," and elsewhere in this Annual Report on Form 10-K. Historical statements made herein are accurate only as of the date of filing of this Annual Report on Form 10-K with the SEC, and may be relied upon only as of that date. The following discussion and analysis should be read in conjunction with Forest's Consolidated Financial Statements and Notes thereto.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Our total estimated proved reserves as of December 31, 2012 were approximately 1,363 Bcfe, all of which are located in our one reportable geographical segment - the United States. Our core operational areas are in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area. See Item 1 "Business" for a discussion of our business strategy and core operational areas of focus.

On June 1, 2011, we completed an initial public offering of approximately 18% of the common stock of our then wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which held our ownership interests in our Canadian operations. On September 30, 2011, we spun-off our remaining shares of Lone Pine to our shareholders by means of a special stock dividend of Lone Pine common shares. As a result of the spin-off, Lone Pine's results of operations are reported as discontinued operations in our Consolidated Statements of Operations for the periods in which we held a controlling financial interest in Lone Pine.

2012 Highlights

Forest's 2012 highlights were as follows:

- Increased total oil and NGL sales volumes to 33% of total equivalent sales volumes compared to 28% in 2011 and 26% in 2010.

- Increased the percentage of oil reserves to 15% of total estimated proved reserves as of December 31, 2012 from 9% as of December 31, 2011, pro forma for the sales of oil and gas properties in 2012.

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Received cash proceeds of $263 million from the non-core property divestiture program we initiated in 2012. In addition, on February 15, 2013, we received $307 million from the sale of certain South Texas properties as a continuing part of the divestiture program.

- Continued the development in the central fairway of our Eagle Ford Shale acreage position in Gonzales County, where we have experienced the most consistent results. We drilled 14 wells in the central fairway of the Eagle Ford Shale during 2012 that had a 30-day average gross production rate of 490 Boe/d (94% oil) and 13 of the wells had a 90-day average gross production rate of 353 Boe/d (94% oil).

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The most productive well completed during 2012 began producing in July and had cumulative production of approximately 70,000 barrels of oil in its first 180 days.

- Drilled eight Missourian Wash Hogshooter wells during 2012 that had a 30-day average gross production rate of 1,820 Boe/d (67% oil) and a 90-day average gross production rate of 1,200 Boe/d (64% oil). The most productive well completed during 2012 began producing in January and had cumulative equivalent production of approximately 450,000 barrels of oil in its first year of sales.

See Item 1 "Business—Recent Trends and 2013 Outlook" for a discussion of recent trends regarding oil, natural gas, and NGL market prices and our 2013 outlook.

Results of Operations

Forest recorded a net loss in 2012 of $1.3 billion as compared to net earnings from continuing operations of $98 million in 2011. The net loss in 2012 was primarily due to ceiling test write-downs and other non-cash property impairments during 2012 totaling $1.1 billion as well as a $245 million valuation allowance placed against prior year's net deferred tax assets primarily as a result of the ceiling test write-downs and property impairments recognized in 2012. See "Critical Accounting Policies, Estimates, Judgments and Assumptions—Valuation of Deferred Tax Assets" for further discussion of our valuation allowance. Adjusted EBIDTA, which is a non-generally accepted accounting principles ("GAAP") performance measure commonly used by management, securities analysts, and investors that excludes non-cash items such as depletion expense, deferred income tax expense, ceiling test write-downs, and impairments, was $514 million in 2012 as compared to $551 million in 2011. The decrease of $37 million was primarily attributable to changes in oil, natural gas, and natural gas liquids ("NGLs") production and prices as well as changes in realized commodity derivative gains between the two periods. See "Reconciliation of Non-GAAP Measure" at the end of this Item 7 for a reconciliation of Adjusted EBITDA to the most directly comparable financial measure calculated and presented in accordance with GAAP.

Oil, Natural Gas, and Natural Gas Liquids Volumes and Revenues

Oil, natural gas, and natural gas liquids sales volumes, revenues, and average sales prices from continuing operations for the years ended December 31, 2012, 2011, and 2010, are set forth in the table below.

	Year Ended December 31,		
	2012	2011	2010
Sales volumes:			
Oil (MBbls)	3,146	2,491	2,357
Natural gas (MMcf)	81,008	88,497	101,346
NGLs (MBbls)	3,489	3,154	3,589
Totals (MMcfe)	120,818	122,367	137,022
Revenues (In Thousands):			
Oil	$302,445	$239,695	$179,312
Natural gas	192,220	328,510	404,415
NGLs	110,858	135,326	123,965
Totals	$605,523	$703,531	$707,692
Average sales price per unit:			
Oil ($/Bbl)	$96.14	$96.22	$76.08
Natural gas ($/Mcf)	2.37	3.71	3.99
NGLs ($/Bbl)	31.77	42.91	34.54
Totals ($/Mcfe)	$5.01	$5.75	$5.16

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Equivalent sales volumes from continuing operations decreased 1% in 2012 as compared to 2011, with the 8% decrease in natural gas volumes being nearly offset by a 26% increase in oil volumes and an 11% increase in NGL volumes. This change in the relative weighting of production by product was the result of our continued focus on the development of liquids-rich prospects in 2012. Total oil and NGL sales volumes increased to 33% of total equivalent sales volumes compared to 28% in 2011 and 26% in 2010. Revenues from oil, natural gas, and NGLs were $606 million in 2012 as compared to $704 million in 2011. The $98 million decrease was primarily the result of the decline in the market price for natural gas and NGLs, partially offset by the increase in oil sales volumes of 655 MBbls, which increased oil revenues in 2012 by $63 million compared to the previous year based on the average sales price realization of $96.14 per barrel in 2012.

Our equivalent sales volumes from continuing operations decreased 11% in 2011 compared to 2010, primarily due to a decrease in natural gas production. Total oil, natural gas, and NGL revenues were essentially flat between 2011 and 2010, primarily with increases in oil and NGL prices being offset by a decrease in natural gas production as well as prices.

The revenues and average sales prices reflected in the table above exclude the effects of commodity derivative instruments because we have elected not to designate our derivative instruments as cash flow hedges. The table below shows the average realized price per unit from continuing operations including the effects of commodity derivative instruments we had in place for the periods presented.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Oil:			
Average sales price ($/Bbl)	$96.14	$96.22	$76.08
Effects of commodity derivatives ($/Bbl)	1.86	(5.05)	(1.62)
Average realized price ($/Bbl)	$98.00	$91.17	$74.45
Natural gas:			
Average sales price ($/Mcf)	$2.37	$3.71	$3.99
Effects of commodity derivatives ($/Mcf)	1.13	.88	1.02
Average realized price ($/Mcf)	$3.51	$4.60	$5.01
NGLs:			
Average sales price ($/Bbl)	$31.77	$42.91	$34.54
Effects of commodity derivatives ($/Bbl)	.76	(8.92)	—
Average realized price ($/Bbl)	$32.54	$33.99	$34.54
Totals:			
Average sales price ($/Mcfe)	$5.01	$5.75	$5.16
Effects of commodity derivatives ($/Mcfe)	.83	.31	.73
Average realized price ($/Mcfe)	$5.84	$6.06	$5.89

See “Realized and Unrealized Gains and Losses on Derivative Instruments” below for more information on gains and losses relating to our commodity derivative instruments.

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Production Expense

The table below sets forth the detail of production expense from continuing operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$108,027	$99,158	$92,394
Production and property taxes	34,249	40,632	43,656
Transportation and processing costs	14,633	13,728	13,242
Production expense	$156,909	$153,518	$149,292
Production expense per Mcfe:			
Lease operating expenses	$.89	$.81	$.67
Production and property taxes	.28	.33	.32
Transportation and processing costs	.12	.11	.10
Production expense per Mcfe	$1.30	$1.25	$1.09

Lease Operating Expenses

Lease operating expenses in 2012 were $108 million, or $.89 per Mcfe, compared to $99 million, or $.81 per Mcfe, in 2011. The $.08 per Mcfe increase in 2012 compared to 2011 was primarily due to increases in water disposal costs and workovers as well as an increase in oil production. Based on the energy-equivalent ratio of six Mcf of natural gas to one barrel of oil, oil production typically has higher per-unit lease operating costs than does natural gas production. However, because the market price of oil relative to natural gas is currently well in excess of the six-to-one ratio, the increase in lease operating expense associated with an increase in oil production is more than offset by the additional revenues realized from oil sales. Lease operating expenses were $99 million, or $.81 per Mcfe, in 2011 compared to $92 million, or $.67 per Mcfe, in 2010. The increase in total and per-unit lease operating expenses was primarily due to an increase in water disposal costs.

Production and Property Taxes

Production and property taxes, consisting primarily of severance taxes paid on the value of the oil, natural gas, and NGLs sold, were 5.7%, 5.8%, and 6.2% of oil, natural gas, and NGL sales for the years ended December 31, 2012, 2011, and 2010, respectively. Normal fluctuations occur in this percentage between periods based upon the timing of approval of incentive tax credits in Texas, changes in tax rates, and changes in the assessed values of oil and gas properties and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were $15 million, or $.12 per Mcfe, in 2012, $14 million, or $.11 per Mcfe, in 2011, and $13 million, or $.10 per Mcfe, in 2010.

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General and Administrative Expense

The following table summarizes the components of general and administrative expense from continuing operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$22,897	$35,706	$31,475
Stock-based compensation costs capitalized	(7,378)	(14,886)	(11,212)
	15,519	20,820	20,263
Other general and administrative costs	74,149	75,792	76,018
Other general and administrative costs capitalized	(30,406)	(31,507)	(31,395)
	43,743	44,285	44,623
General and administrative expense	$59,262	$65,105	$64,886
General and administrative expense per Mcfe	$.49	$.53	$.47

General and administrative expense was $59 million in 2012 compared to $65 million in both 2011 and 2010. The primary reason for the decrease was due to a decrease in stock-based compensation costs in 2012 compared to 2011. Stock-based compensation costs decreased primarily due to the decrease in our stock price. Additionally, $12 million in stock-based compensation costs ($7 million of expense, net of capitalized amounts) were recognized in 2011 related to the spin-off of Lone Pine, which caused the forfeiture restrictions to lapse on a portion of each outstanding restricted stock award, thus requiring the immediate recognition of compensation cost. This decrease in stock-based compensation costs was partially offset by $5 million in accelerated stock-based compensation costs ($4 million of expense, net of capitalized amounts) related to the termination of our former chief executive officer, which was recognized during the second quarter of 2012. The percentage of general and administrative costs capitalized remained consistent between the three years presented, ranging between 39% and 42%.

Depreciation, Depletion, and Amortization

The following table summarizes depreciation, depletion, and amortization expense from continuing operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$280,458	$219,684	$187,973
Depreciation, depletion, and amortization expense per Mcfe	$2.32	$1.80	$1.37

Depreciation, depletion, and amortization expense (“DD&A”) increased $.52 per Mcfe to $2.32 per Mcfe in 2012 compared to $1.80 per Mcfe in 2011. The increase in DD&A from 2011 to 2012 is due primarily to the increase in oil reserve additions since 2011, which typically have higher per-unit development costs than natural gas reserves. In addition, in 2012, a significant portion of our proved undeveloped natural gas reserves, which have lower associated development costs than do proved undeveloped oil reserves, were reclassified from proved to probable status in conjunction with the decrease in the natural gas prices used to determine our proved reserves. This reclassification also contributed to the increase in our DD&A rate.

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Ceiling Test Write-Down of Oil and Natural Gas Properties

In 2012, we recorded ceiling test write-downs of our United States cost center totaling $958 million, pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting. These ceiling test write-downs were primarily a result of the decline in the twelve-month arithmetic average prices of natural gas and NGLs that were used to calculate the present value of future net revenues from our estimated proved oil and natural gas reserves throughout 2012. Additional write-downs of our oil and natural gas properties may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, or NGL prices used in the calculation of the present value of future net revenues from estimated production of proved oil and natural gas reserves declines compared to prices used as of December 31, 2012, unproved property values decrease, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any, attributable to the cost center. See "Critical Accounting Policies, Estimates, Judgments and Assumptions—Full Cost Method of Accounting" for more information regarding ceiling test write-downs.

In April 2012, an Italian regional regulatory body denied approval of an environmental impact assessment associated with our proposal to commence natural gas production from wells that we drilled and completed in 2007. We are currently appealing the region's denial; however, until the region's denial is reversed or overturned, we determined that we could no longer conclude with reasonable certainty that our Italian natural gas reserves are producible. Accordingly, we reclassified the Italian reserves from proved to probable effective in the first quarter of 2012 and recorded a ceiling test write-down of our Italian cost center of $35 million.

Impairment of Properties

During the third quarter of 2012, we recorded a $67 million impairment of our unproved properties in South Africa based on several unsuccessful attempts to sell the properties for an amount that would allow us to recover the carrying amount of our investment in these properties. Because we have no proved reserves in South Africa, the impairment was reported as a period expense rather than being added to the costs to be amortized and is included in the Consolidated Statement of Operations within the "Impairment of properties" line item. In December 2012, we entered into agreements to sell our South African subsidiaries and abandon a certain exploration right in South Africa. See Note 2 to the Consolidated Financial Statements for more information regarding this planned divestiture.

In August 2012, we entered into an agreement to sell the majority of our East Texas natural gas gathering assets for $34 million in cash and the transaction closed in October 2012. During the third quarter of 2012, these assets were written down to their estimated fair value less cost to sell, with a $13 million impairment charge included in the Consolidated Statement of Operations within the "Impairment of properties" line item. See Note 2 to the Consolidated Financial Statements for more information regarding this divestiture.

Interest Expense

The following table summarizes interest expense from continuing operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Interest costs	$149,054	$160,014	$161,139
Interest costs capitalized	(7,223)	(10,259)	(11,248)
Interest expense	$141,831	$149,755	$149,891

Interest expense in 2012 totaled $142 million compared to $150 million in 2011. The $8 million decrease in interest expense was primarily attributable to the redemption of $285 million of 8% senior notes in December 2011 and the redemption of $300 million of 8½% senior notes in October 2012, partially offset by an increase in interest

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costs incurred on borrowings under our bank credit facility in 2012, interest costs on the 7½% senior notes issued in September 2012, and lower capitalized interest in 2012. Interest costs capitalized relate to our investments in significant unproved acreage positions that are under development. Interest expense totaled $150 million in both 2011 and 2010.

In order to reduce our concentration of fixed-rate debt, we have entered into fixed-to-floating interest rate swaps under which we have swapped, as of December 31, 2012, $500 million in notional amount at an 8.5% fixed rate for an equal notional amount at a weighted-average interest rate equal to the 1-month LIBOR plus approximately 5.9%. We recognized realized gains under these interest rate swaps of $11 million during each of the years ended December 31, 2012, 2011, and 2010. These gains are recorded as realized gains on derivatives rather than as a reduction to interest expense since we have not elected to use hedge accounting. See Note 9 to the Consolidated Financial Statements for more information on our interest rate derivatives.

Realized and Unrealized Gains and Losses on Derivative Instruments

The table below sets forth realized and unrealized gains and losses on derivatives from continuing operations, which are recognized under "Costs, expenses, and other" in our Consolidated Statements of Operations for the periods indicated. See Note 8 and Note 9 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Realized (gains) losses on derivative instruments, net:			
Oil	$(5,862)	$12,584	$3,825
Natural gas	(91,891)	(78,247)	(103,587)
NGLs	(2,667)	28,128	—
Interest	(11,352)	(11,442)	(12,450)
Subtotal realized gains on derivative instruments, net	(111,772)	(48,977)	(112,212)
Unrealized (gains) losses on derivative instruments, net:			
Oil	(6,324)	(10,297)	18,978
Natural gas	43,350	(22,931)	(47,078)
NGLs	(5,396)	(4,314)	9,710
Interest	7,496	(1,545)	(19,530)
Subtotal unrealized losses (gains) on derivative instruments, net	39,126	(39,087)	(37,920)
Realized and unrealized gains on derivatives, net	$(72,646)	$(88,064)	$(150,132)

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Other, Net

The table below sets forth the components of “Other, net” in the Consolidated Statements of Operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Accretion of asset retirement obligations	$6,663	$6,082	$6,158
Legal proceeding liabilities	29,251	6,500	—
Loss (gain) on debt extinguishment, net	36,312	—	(4,576)
Other, net	11,180	4,582	5,757
	$83,406	$17,164	$7,339

See Note 11 to the Consolidated Financial Statements for more information on the components of “Other, net”.

Income Tax

The table below sets forth total income tax and the effective income tax rates related to continuing operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands, Except Percentages)		
Current income tax	$(35,538)	$30,141	$(13,901)
Deferred income tax	208,975	58,994	123,671
Total income tax	$173,437	$89,135	$109,770
Effective income tax rate	(16)%	48%	37%

Our effective income tax rates were (16)%, 48%, and 37% for the years ended December 31, 2012, 2011, and 2010, respectively. The significant difference between our blended federal and state statutory income tax rate of 36% and our effective income tax rate of (16)% in 2012 was primarily due to a $576 million valuation allowance placed against our deferred tax assets in 2012. Without this valuation allowance, our effective income tax rate would have been 35% in 2012. The current income tax credit provision in 2012 of $36 million primarily relates to income tax refunds filed during 2012 associated with tax loss carrybacks to recover income taxes paid in 2009. Our effective income tax rate was 48% in 2011 due to the Canadian dividend tax of $29 million that was incurred on a stock dividend declared and paid by our former Canadian subsidiary, Lone Pine Resources Canada Ltd. (“LPR Canada”), to Forest, as parent, immediately before Forest’s contribution of LPR Canada to Lone Pine in conjunction with Lone Pine’s initial public offering. Without the $29 million dividend tax, our effective income tax rate would have been 38% in 2011.

See “Critical Accounting Policies, Estimates, Judgments and Assumptions—Valuation of Deferred Tax Assets” for further discussion of our valuation allowance and Note 4 to the Consolidated Financial Statements for a reconciliation of income tax computed using the federal statutory income tax rate to income tax computed using our effective income tax rate for each period presented.

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Discontinued Operations

The results of operations of Lone Pine are presented as discontinued operations in our Consolidated Statements of Operations for 2011 and 2010 due to the spin-off of Lone Pine on September 30, 2011. See Note 13 to the Consolidated Financial Statements for more information regarding the components of earnings from discontinued operations.

Liquidity and Capital Resources

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facility as our primary sources of liquidity. To fund large transactions, such as acquisitions and debt refinancing transactions, we have looked to the private and public capital markets as another source of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil, natural gas, and natural gas liquids directly impact our level of cash flow generated from operations. Natural gas accounted for approximately 67% of our total production in 2012 and, as a result, our operations and cash flow are more sensitive to fluctuations in the market price for natural gas than to fluctuations in the market prices for oil and natural gas liquids. We employ a commodity hedging strategy as an attempt to moderate the effects of wide fluctuations in commodity prices on our cash flow. As of February 21, 2013, we had hedged, via commodity swaps, approximately 67 Bcfe of our total projected 2013 production and approximately 29 Bcf of our total projected 2014 production, excluding outstanding commodity swaptions. This level of hedging will provide a measure of certainty with respect to the cash flow that we will receive for a portion of our future production. However, these hedging activities may result in reduced income or even financial losses to us. See Part I, Item 1A "Risk Factors—Our use of hedging transactions could reduce our cash flow and/or result in reported losses," for further details of the risks associated with our hedging activities. In the future, we may determine to increase or decrease our hedging positions. As of February 21, 2013, all but one of our derivative instrument counterparties are lenders, or affiliates of lenders, under our credit facility. See Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk," below for more information on our derivative contracts.

As noted above, the other primary source of liquidity is our credit facility, which had a borrowing base of $1.07 billion as of December 31, 2012. In connection with the closing of our South Texas divestiture, the borrowing base was reduced to $900 million effective February 15, 2013. This facility is used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facility is secured by a portion of our assets, with the facility maturing in June 2016. See "Bank Credit Facility" below for further details. We had $65 million of borrowings outstanding under our credit facility as of December 31, 2012 and had no borrowings outstanding at February 21, 2013. As noted below under "Bank Credit Facility," our credit facility contains a covenant that we will not permit our ratio of total debt outstanding to EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.5 to 1.0 at any time. Depending on our overall level of indebtedness, this covenant may limit our ability to borrow funds as needed under our credit facility. See Part I, Item 1A "Risk Factors—Our debt agreements contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities," for the risks associated with the restrictive covenants in our debt agreements, including the credit agreement.

The public and private capital markets have served as our primary source of financing to fund large acquisitions and other exceptional transactions, such as debt refinancings. In the past, we have issued debt and equity in both the public and private capital markets. For example, we completed a private offering of $500 million of 7½% senior notes due 2020 in September 2012, using some of the proceeds to redeem $300 million of our 8½% senior notes due 2014. Our ability to access the debt and equity capital markets on economic terms is affected by general economic conditions, the domestic and global financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of our equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

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See Note 3 and Note 5 to the Consolidated Financial Statements for more information regarding our debt and equity, respectively.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, during 2012, 2011, and 2010, we sold various non-core assets for approximately $263 million, $121 million, and $139 million, respectively. In February 2013, we sold all of our oil and natural gas properties located in South Texas, excluding our Eagle Ford Shale oil properties, for net proceeds of $307 million, which we plan to use in March 2013 to redeem the remaining $300 million of our outstanding 8½% senior notes due 2014.

We believe that our cash flows provided by operating activities and the funds available under our credit facility will be sufficient to fund our normal recurring operating needs, anticipated capital expenditures, and our contractual obligations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions, a significant decline in commodity prices, or a continuation of depressed natural gas prices, we may elect to reduce our planned capital expenditures, as we did in the second half of 2012. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A “Risk Factors,” for a discussion of the risks and uncertainties that affect our business and financial and operating results.

Bank Credit Facility

On June 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the “Credit Facility”) with a syndicate of banks led by JPMorgan Chase Bank, N.A. (the “Administrative Agent”) consisting of a $1.5 billion credit facility maturing in June 2016. The size of the Credit Facility may be increased by $300 million, to a total of $1.8 billion, upon agreement between us and the applicable lenders.

Our availability under the Credit Facility is governed by a borrowing base. As of December 31, 2012, the borrowing base under the Credit Facility was $1.07 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of our oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders’ customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. A lowering of the borrowing base could require us to repay indebtedness in excess of the borrowing base in order to cover the deficiency. The last scheduled semi-annual redetermination of the borrowing base occurred in October 2012 and resulted in a $50 million reduction to the borrowing base. The next scheduled semi-annual redetermination of the borrowing base will occur on or about May 1, 2013. In addition to the scheduled semi-annual redeterminations, we and the lenders each have discretion at any time, but not more often than once during a calendar year, to have the borrowing base redetermined.

The borrowing base is also subject to automatic adjustments if certain events occur, such as if we or any of our Restricted Subsidiaries (as defined in the Credit Facility) issue senior unsecured notes, in which case the borrowing base will immediately be reduced by an amount equal to 25% of the stated principal amount of such issued senior notes, excluding any senior unsecured notes that we or any of our Restricted Subsidiaries may issue to refinance senior notes that were outstanding on June 30, 2011. This was the case in September 2012, when the borrowing base was reduced by $50 million. The borrowing base is also subject to automatic adjustment if we or any of our Restricted Subsidiaries sell oil and natural gas properties included in the borrowing base, as applicable, having a fair market value in excess of 10% of the borrowing base then in effect. In this case, the borrowing base will be reduced by an amount either (i) equal to the percentage of the borrowing base attributable to the sold properties, as determined by the Administrative Agent, or (ii) if none of the borrowing base is attributable to the sold properties, a value agreed upon by us and the required lenders. The sale of our South Louisiana properties resulted in an $80 million reduction to the borrowing base when the transaction closed in November 2012 and the sale of our South Texas properties resulted in a $170 million reduction to the borrowing base when the transaction closed in February 2013, bringing the borrowing base to $900 million. See Note 2 to the Consolidated Financial Statements for more information regarding these divestitures.

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The Credit Facility is collateralized by our assets. Under the Credit Facility, we are required to mortgage and grant a security interest in 75% of the present value of the estimated proved oil and gas properties and related assets. If our corporate credit ratings issued by Moody's and S&P meet pre-established levels, the security requirements would cease to apply and, at our request, the banks would release their liens and security interest on our properties.

Borrowings under the Credit Facility bear interest at one of two rates as may be elected by us. Borrowings bear interest at:

(i) the greatest of (a) the prime rate announced by JPMorgan Chase Bank, N.A., (b) the federal funds effective rate from time to time plus ½ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by us) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or

(ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 basis points, depending on borrowing base utilization.

The Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also includes a financial covenant. The Credit Facility provides that we will not permit our ratio of total debt outstanding to EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.5 to 1.0 at any time. Our ratio of total debt outstanding to EBITDA for the twelve-month period ended December 31, 2012, as calculated in accordance with the Credit Facility, was 4.2. We expect to continue to meet this covenant by maintaining our capital expenditures at levels that approximate our cash flows from operating activities in subsequent quarters and by using proceeds from the sale of non-core assets such as our South Texas properties to reduce debt.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated. Bankruptcy and insolvency events with respect to us or certain of our subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. Subject to notice and cure periods, certain events of default under the Credit Facility will result in acceleration of the indebtedness under the Credit Facility at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the Credit Facility (including the financial covenant), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the Credit Facility.

Of the $1.5 billion total nominal amount under the Credit Facility, JPMorgan and ten other banks hold approximately 68% of the total commitments. With respect to the other 32% of the total commitments, no single lender holds more than 3.3% of the total commitments. Commitment fees accrue on the amount of unutilized borrowing base. If borrowing base utilization is greater than 50%, commitment fees are 50 basis points of the unutilized amount, and if borrowing base utilization is 50% or less, commitment fees are 35 basis points of the unutilized amount.

At December 31, 2012, there were outstanding borrowings of $65 million under the Credit Facility at a weighted average interest rate of 2.1% and we had used the Credit Facility for $2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.0 billion. At February 21, 2013, there were no borrowings outstanding under the Credit Facility and we had used the Credit Facility for $2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $898 million.

Credit Ratings

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody’s Investors Service and Standard & Poor’s Ratings Services currently rate each series of our senior notes and, in addition, they have

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assigned Forest a general credit rating. Our Credit Facility includes provisions that are linked to our credit ratings. For example, our collateral requirements will vary based on our credit ratings; however, we do not have any credit rating triggers that would accelerate the maturity of amounts due under the Credit Facility or the debt issued under the indentures for our senior notes. The indentures for our senior notes also include terms linked to our credit ratings. These terms allow us greater flexibility if our credit ratings improve to investment grade and other tests have been satisfied, in which event we would not be obligated to comply with certain restrictive covenants included in the indentures. Our ability to raise funds and the costs of any financing activities will be affected by our credit ratings at the time any such financing activities are conducted.

Historical Cash Flow

Net cash provided by operating activities of continuing operations, net cash used by investing activities of continuing operations, and net cash provided (used) by financing activities of continuing operations for the years ended December 31, 2012, 2011, and 2010 were as follows:

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Net cash provided by operating activities of continuing operations	$371,655	$398,097	$446,725
Net cash used by investing activities of continuing operations	(467,782)	(759,730)	(423,054)
Net cash provided (used) by financing activities of continuing operations	94,171	(173,305)	(142,211)

Net cash provided by operating activities of continuing operations is primarily affected by sales volumes and commodity prices net of the effects of settlements of our derivative contracts and changes in working capital. The decrease in net cash provided by operating activities of continuing operations of $26 million in 2012 as compared to 2011 was primarily due to a $98 million decrease in revenue that was partially offset by an increase in realized gains on commodity derivatives of $63 million. The decrease in net cash provided by operating activities of continuing operations of $49 million in 2011 as compared to 2010 was primarily due to lower realized gains on commodity derivative instruments of $62 million and an increase in current income tax expense of $44 million, both of which were partially offset by a decreased investment in net operating assets (i.e., working capital) of $69 million.

The components of net cash used by investing activities of continuing operations for the years ended December 31, 2012, 2011, and 2010 were as follows:

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Exploration, development, acquisition, and leasehold costs[1]	$(721,536)	$(873,877)	$(556,988)
Proceeds from sales of assets	262,882	121,115	139,077
Other fixed asset costs	(9,128)	(6,968)	(5,143)
Net cash used by investing activities of continuing operations	$(467,782)	$(759,730)	$(423,054)

(1) Cash paid for exploration, development, acquisition, and leasehold costs as reflected in the Consolidated Statements of Cash Flows differs from the reported capital expenditures in the "Capital Expenditures" table below due to the timing of when the capital expenditures are incurred and when the actual cash payments are made as well as non-cash capital expenditures such as the value of common stock issued for oil and natural gas property acquisitions and capitalized stock-based compensation costs.

Net cash used by investing activities of continuing operations is primarily comprised of expenditures for the acquisition, exploration, and development of oil and gas properties net of proceeds from the dispositions of oil and gas properties and other capital assets. The $292 million decrease in cash used for investing activities of continuing operations between 2012 and 2011 was primarily due to a decrease in leasehold acquisition costs and an increase in proceeds from sales of assets in 2012 as compared to 2011. The $337 million increase in cash used for

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investing activities of continuing operations between 2011 and 2010 was primarily due to an increase in leasehold acquisition costs and exploration and development expenditures in 2011 as compared to 2010.

Net cash provided by financing activities of continuing operations of $94 million in 2012 primarily included the issuance of the 7½% senior notes due 2020 for net proceeds of $491 million, partially offset by the redemption of the 8½% senior notes due 2014 for $331 million, including the $31 million call premium, net credit facility repayments of $40 million, and a decrease in bank overdrafts of $24 million. Net cash used by financing activities of continuing operations of $173 million in 2011 primarily included the redemption of the 8% senior notes due 2011 for $285 million, partially offset by net credit facility borrowings of $105 million. Net cash used by financing activities of continuing operations of $142 million in 2010 primarily included the redemption of the 7¾% senior notes due 2014 for $152 million, including the $2 million call premium.

Capital Expenditures

Expenditures of continuing operations for property exploration, development, and acquisitions were as follows:

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Property Acquisitions:			
Proved properties	$—	$—	$5,823
Unproved properties including leasehold acquisition costs	64,057	204,537	64,593
	64,057	204,537	70,416
Exploration:			
Direct costs	250,302	272,422	172,746
Overhead capitalized	19,157	20,964	22,241
	269,459	293,386	194,987
Development:			
Direct costs	380,496	392,406	299,461
Overhead capitalized	18,627	25,429	20,366
	399,123	417,835	319,827
Total capital expenditures[1]	$732,639	$915,758	$585,230

(1) Total capital expenditures include cash expenditures, accrued expenditures, and non-cash capital expenditures including the value of common stock issued for oil and natural gas property acquisitions and stock-based compensation capitalized under the full cost method of accounting. Total capital expenditures also include changes in estimated discounted asset retirement obligations of $6 million, $3 million, and $(1) million recorded during the years ended December 31, 2012, 2011, and 2010, respectively.

We have established an exploration and development capital budget of $355 million to $375 million for 2013, which we anticipate will approximate our cash flow based on expected commodity prices and continues our focus on higher-margin oil opportunities. Primary factors impacting the level of our capital expenditures include oil and natural gas prices, the volatility in these prices, the cost and availability of oil field services, general economic and market conditions, and weather disruptions.

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Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2012:

	2013	2014	2015	2016	2017	After 2017	Total
	(In Thousands)						
Bank debt(1)	$4,916	$4,916	$4,916	$67,458	$—	$—	$82,206
Senior notes(2)	135,512	413,188	110,000	110,000	110,000	1,707,292	2,585,992
Derivative liabilities(3)	9,347	7,204	—	—	—	—	16,551
Other liabilities(4)	7,510	12,676	8,527	7,741	7,755	86,521	130,730
Operating leases(5)	30,070	24,188	17,573	17,026	10,032	10,135	109,024
Unconditional purchase obligations(6)	4,165	140	105	—	—	—	4,410
Total contractual obligations	$191,520	$462,312	$141,121	$202,225	$127,787	$1,803,948	$2,928,913

(1) Bank debt consists of the $65 million outstanding balance under our credit facility as of December 31, 2012, as well as the anticipated interest payments on that balance and commitment and letter of credit fees, all based on the actual rates in effect as of December 31, 2012 and the $1.07 billion borrowing base and $2 million in outstanding letters of credit as of December 31, 2012, assuming all such balances remain outstanding until the maturity of the credit facility.

(2) Senior notes consist of the principal obligations on our senior notes and senior subordinated notes and anticipated interest payments due on each, assuming all notes remain outstanding in full until their respective maturities.

(3) Derivative liabilities represent the fair value of our derivative liabilities as of December 31, 2012. The ultimate settlement amounts of our derivative liabilities are unknown, because they are subject to continuing market risk. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in valuing derivative instruments.

(4) Other liabilities are comprised of pension and other postretirement benefit obligations and asset retirement obligations, for which neither the ultimate settlement amounts nor the timing of settlement can be precisely determined in advance. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(5) Operating leases consist of leases for drilling rigs, compressors, and office facilities and equipment.

(6) Unconditional purchase obligations consist primarily of drilling commitments, throughput obligations, and voice and data services.

We also make delay rental payments to lessors during the primary terms of oil and gas leases to delay drilling or production of wells, usually for one year. Although we are not obligated to make such payments, discontinuing them would result in the loss of the oil and gas lease. Our estimated maximum commitment of future delay lease rental payments, through 2020, totaled approximately $5 million as of December 31, 2012.

Off-balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and other transactions that can give rise to off-balance sheet obligations. As of December 31, 2012, the off-balance sheet arrangements and other transactions that we have entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, and (iv) other contractual obligations for which we have recorded estimated liabilities on the balance sheet, but the ultimate settlement amounts are not fixed and determinable, such as derivative contracts, pension and other postretirement benefit obligations, and asset retirement obligations. We do not believe that any of these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Surety Bonds

In the ordinary course of our business and operations, we are required to post surety bonds from time to time with third parties, including governmental agencies. In addition, while we appeal the arbitration award in Forest Oil Corporation, et al. v. El Rucio Land & Cattle Company, Inc., et al. (see Item 3 “Legal Proceedings”), we are required to post a supercedeas bond. As of February 21, 2013, we had obtained this supercedeas bond as well as surety bonds from a number of insurance and bonding institutions covering certain of our current and former operations in the United States in the aggregate amount of approximately $39 million. See Part I, Item 1 “Business—Industry Regulation” for further information.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

Full Cost Method of Accounting

The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the full cost method and the successful efforts method. The differences between the two methods can lead to significant variances in the amounts reported in financial statements. We have elected to follow the full cost method, which is described below.

Under the full cost method, separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) are capitalized. The fair value of estimated future costs of site restoration, dismantlement, and abandonment activities is capitalized, and a corresponding asset retirement obligation liability is recorded.

Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Changes in estimates of reserves or future development costs are accounted for in the current quarter and prospectively in the depletion calculations. We have historically updated our quarterly depletion calculations with our quarter-end reserves estimates. Based on this accounting policy, our December 31, 2012 reserves estimates were used for our fourth quarter 2012 depletion calculation. See Part I, Item 1, “Business—Reserves” and Note 15 to the Consolidated Financial Statements for a more complete discussion of our estimated proved reserves as of December 31, 2012.

Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter for each cost center. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from estimated proved oil and natural gas reserves calculated using current prices, which are the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and NGL prices. This ceiling is compared to the net book value of the oil and gas properties reduced by any related net deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, a non-cash write-down is required. In 2012, Forest recorded ceiling test write-downs in the United States cost center totaling $958 million and in the Italian cost center totaling $35 million. The United States ceiling test write-downs were primarily a result of the decline in the twelve-month arithmetic average prices of natural gas and NGLs.

In areas where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs, and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. If exploration activities result in the establishment of proved reserves, amounts are reclassified as proved properties and become subject to depreciation, depletion, and amortization, and the application of the ceiling limitation. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, geographic and geologic data obtained relating to the properties, and estimated discounted future net cash flows from the properties. Where it is not practicable to individually assess properties whose costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool, or reported as impairment expense in the Consolidated Statements of Operations, as applicable. During the year ended December 31, 2012, we recorded a $67 million impairment of our unproved properties in South Africa based on several unsuccessful

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attempts to sell the properties for an amount that would allow us to recover the carrying amount of our investment in these properties. Because we have no proved reserves in South Africa, and therefore no costs being amortized, the impairment was reported as a period expense and is included in the Consolidated Statement of Operations within the "Impairment of properties" line item.

Under the alternative successful efforts method of accounting, surrendered, abandoned, and impaired leases, delay lease rentals, exploratory dry holes, and overhead costs are expensed as incurred. Capitalized costs are depleted on a property-by-property basis. Impairments are also assessed on a property-by-property basis and are charged to expense when assessed.

The full cost method is used to account for our oil and gas exploration and development activities because we believe it appropriately reports the costs of our exploration programs as part of an overall investment in discovering and developing proved reserves.

Goodwill

Goodwill is tested for impairment on an annual basis in the second quarter of the year. In addition, we test goodwill for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

In the first step of testing for goodwill impairment, we estimate the fair value of our reporting unit, which we have determined to be our U.S. geographic operating segment, and compare the fair value with the carrying value of the net assets assigned to the reporting unit. If the fair value is greater than the carrying value, then no impairment results. If the fair value is less than the carrying value, then we perform a second step and determine the fair value of the goodwill. In this second step, the fair value of goodwill is determined by deducting the fair value of a reporting unit's identifiable assets and liabilities from the fair value of the reporting unit as a whole, as if that reporting unit had just been acquired and the purchase price was being initially allocated. If the fair value of the goodwill is less than its carrying value for a reporting unit, an impairment charge would be recorded to earnings in the Consolidated Statement of Operations.

To determine the fair value of our reporting unit, we calculate the market capitalization of our reporting unit based on our quoted stock price. Quoted prices in active markets are the best evidence of fair value. Because value results from the ability to take advantage of synergies and other benefits that exist from a collection of assets and liabilities that operate together in a controlled entity, the market capitalization of a reporting unit with publicly traded equity securities may not be representative of the fair value of the reporting unit as a whole. Therefore, we add a control premium to the market capitalization. Additionally, we subtract an estimated amount that market participants would attribute to our stock price for the value of our international operations, to which no goodwill has been allocated. The sum of our market capitalization and control premium, less the international value, is the fair value of our reporting unit. This amount is then compared to the carrying value of our reporting unit.

In performing step two of the goodwill impairment test, one of the more significant estimates is determining the fair value of our oil and gas properties. To determine the fair value of our oil and gas properties, we use a discounted cash flow model to value our total estimated reserves, which include proved, probable, and possible reserves. This approach relies on significant judgments about the quantity of reserves, the timing of the expected production, the pricing that will be in effect at the time of production, and the appropriate discount rates to be used. Our discount rate assumptions are based on an assessment of Forest's weighted average cost of capital.

At the time of our annual 2012 goodwill impairment test, the fair value of the reporting unit exceeded its carrying value. The market capitalization alone, without adjustments for the control premium and international value, also exceeded the carrying value. Subsequent to the completion of our annual test, we performed an interim quarterly test due to the loss of key personnel in the second quarter. We did not record a goodwill impairment charge during the year ended December 31, 2012. However, due to the significant judgments that go into the goodwill impairment test, as discussed above, there can be no assurance that our goodwill will not be impaired at any time in the future.

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Oil and Gas Reserves Estimates

Our estimates of proved reserves are based on the quantities of oil and 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 regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The accuracy of any reserves estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production and property taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as oil, natural gas, and NGL prices that we are required to use pursuant to SEC regulations change from period-to-period, the estimate of proved reserves will also change and the change can be significant. Despite the inherent uncertainty in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a ceiling test limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures included in Note 15 to the Consolidated Financial Statements.

Reference should be made to “Reserves” under Part I, Item 1 “Business,” and “Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition,” under Part I, Item 1A “Risk Factors,” in this Annual Report on Form 10-K.

Fair Value of Derivative Instruments

We use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and option-pricing models for valuing our collars, swaptions, and puts. Inputs to these valuation techniques include published forward prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. The values we report in our financial statements change as these estimates are revised to reflect changes in market conditions or other factors, many of which are beyond our control.

The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of operations, because changes in fair value of the derivative offset changes in the fair value of the hedged item. Where hedge accounting is not elected, or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings as other income or expense. We have elected not to use hedge accounting to account for our derivative instruments and, as a result, all changes in the fair values of our derivative instruments are recognized in earnings as unrealized gains or losses in the line item “Realized and unrealized gains on derivative instruments, net” in our Consolidated Statements of Operations.

Due to the volatility of oil, natural gas, and natural gas liquids prices and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Item 7A “Quantitative and Qualitative Disclosures about Market Risk” for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

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Valuation of Deferred Tax Assets

We use the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are determined based on differences between the financial statement carrying values of assets and liabilities and their respective income tax bases (temporary differences). Income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect of a change in tax rates on income tax assets and liabilities is included in earnings in the period in which the change is enacted. The book value of income tax assets is limited to the amount of the tax benefit that is more likely than not to be realized in the future.

In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. In making this assessment, we consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies, and projected future taxable income. If the ultimate realization of deferred tax assets is dependent upon future book income, assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive, as to whether it is more likely than not that a deferred tax asset will be realized.

Negative evidence considered by us included a three-year cumulative book loss driven primarily by the ceiling test write-downs incurred in 2012. Positive evidence considered by us included forecasted book income in future years based on expected future oil, natural gas, and NGL production and expected commodity prices based on NYMEX oil and natural gas futures. Based upon the evaluation of what we determined to be relevant evidence, we have recorded a valuation allowance of $576 million against our deferred tax assets as of December 31, 2012. Although we expect future book income based on future production and future NYMEX oil and natural gas prices, oil and natural gas prices have been highly volatile over recent years, and only a portion of our forecasted production is hedged through the end of 2014.

Asset Retirement Obligations

Forest has obligations to remove tangible equipment and restore locations at the end of the oil and gas production operations. Estimating the future restoration and removal costs, or asset retirement obligations (“ARO”), requires us to make estimates and judgments, because most of the obligations are many years in the future, and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs periodically change, as do regulatory, political, environmental, safety, and public relations considerations.

Inherent in the calculation of the present value of our ARO are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, which is included in “Other, net” in the Consolidated Statements of Operations.

Impact of Recently Issued Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities (“ASU 2011-11”), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement. In January 2013, the FASB issued ASU 2013-01, Balance Sheet (Topic 210) Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which limits the scope of ASU No. 2011-11 to derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions. ASU 2011-11 was issued in order to facilitate comparison of financial statements prepared under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards by requiring enhanced disclosures, but does not change existing U.S. GAAP, which permits

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balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations, but will require us to make additional disclosures regarding our derivative instruments.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220) Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income ("ASU 2013-02"). ASU 2013-02 does not change the current requirements for reporting net earnings or other comprehensive income in financial statements. However, it requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net earnings, but only if the amount reclassified is required under U.S. GAAP to be reclassified to net earnings in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net earnings, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This authoritative guidance is effective prospectively for annual reporting periods beginning after December 15, 2012, and interim periods within those annual periods. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations. We are currently evaluating the impact adoption of this authoritative guidance may have on our disclosures.

Reconciliation of Non-GAAP Measure

Adjusted EBITDA

In addition to reporting net earnings (loss) from continuing operations as defined under GAAP, we also present adjusted earnings from continuing operations before interest, income taxes, depreciation, depletion, and amortization ("Adjusted EBITDA"), which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings from continuing operations before interest expense, income taxes, depreciation, depletion, and amortization, as well as other non-cash operating items such as unrealized gains and losses on derivative instruments and accretion of asset retirement obligations and other items presented in the table below. Adjusted EBITDA does not represent, and should not be considered an alternative to, GAAP measurements, such as net earnings (loss) from continuing operations (its most comparable GAAP financial measure), and our calculations thereof may not be comparable to similarly titled measures reported by other companies. By eliminating interest, taxes, depreciation, depletion, amortization, and other items from earnings, we believe the result is a useful measure across time in evaluating our fundamental core operating performance. Management also uses Adjusted EBITDA to manage our business, including in preparing our annual operating budget and financial projections. We believe that Adjusted EBITDA is also useful to investors because similar measures are frequently used by securities analysts, investors, and other interested parties in their evaluation of companies in similar industries. Our management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net earnings (loss) from continuing operations and revenues, to measure operating performance. The following table provides a reconciliation of net earnings (loss) from continuing operations, the most directly comparable GAAP measure, to Adjusted EBITDA for the periods presented.

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	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Net earnings (loss) from continuing operations	$(1,288,931)	$98,260	$189,662
Income tax expense	173,437	89,135	109,770
Unrealized losses (gains) on derivative instruments, net	39,126	(39,087)	(37,920)
Interest expense	141,831	149,755	149,891
Loss (gain) on debt extinguishment, net	36,312	—	(4,576)
Accretion of asset retirement obligations	6,663	6,082	6,158
Ceiling test write-down of oil and natural gas properties	992,404	—	—
Impairment of properties	79,529	—	—
Depreciation, depletion, and amortization	280,458	219,684	187,973
Stock-based compensation	15,074	20,536	18,143
Legal proceeding/severance costs	31,102	6,500	—
Rig stacking	6,604	—	—
Adjusted EBITDA from continuing operations	$513,609	$550,865	$619,101

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to market risk, including the effects of adverse changes in commodity prices, interest rates, and foreign currency exchange rates as discussed below.

Commodity Price Risk

We produce and sell natural gas, oil, and NGLs in the United States. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. In order to reduce the impact of fluctuations in commodity prices, or to protect the economics of property acquisitions, we make use of a commodity hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars, and other derivative instruments with counterparties who, in general, are lenders, or affiliates of such lenders, in our credit facility. These arrangements, which are typically based on prices available in the financial markets at the time the contracts are entered into, are settled in cash and do not require physical deliveries of hydrocarbons.

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower than the fixed price. If the index price is higher, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2012, we had entered into the following swaps:

Commodity Swaps

	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
Swap Term	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2013	160	$3.98	$25,349	4,000	$95.53	$3,341
Calendar 2014	40	4.50	6,775	—	—	—

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Commodity Options

In connection with several natural gas and oil swaps entered into, we granted swaptions to the swap counterparties in exchange for our receiving premium hedged prices on the natural gas and oil swaps. These swaptions grant the swap counterparties the option to enter into future swaps with us and may not be exercised until their expiration dates. The table below sets forth the outstanding swaptions as of December 31, 2012.

Commodity Options

		Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
Underlying Term	Option Expiration	Underlying Bbtu Per Day	Underlying Hedged Price per MMBtu	Fair Value (In Thousands)	Underlying Barrels Per Day	Underlying Hedged Price per Bbl	Fair Value (In Thousands)
Gas Swaptions:							
Calendar 2014	December 2013	30	$4.50	$(2,349)	—	$—	$—
Calendar 2014	December 2013	10	4.51	(778)	—	—	—
Oil Swaptions:							
Calendar 2014	December 2013	—	—	—	2,000	110.00	(1,776)
Calendar 2014	December 2013	—	—	—	1,000	109.00	(954)
Calendar 2014	December 2013	—	—	—	2,000	100.00	(3,490)
Calendar 2015	December 2014	—	—	—	3,000	100.00	(7,204)

The estimated fair value at December 31, 2012 of all our commodity derivative instruments based on various inputs, including published forward prices, was a net asset of approximately $19 million.

Due to the volatility of oil, natural gas, and NGL prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. For example, a hypothetical 10% increase in the forward oil, natural gas, and NGL prices used to calculate the fair values of our commodity derivative instruments at December 31, 2012 would decrease the net fair value of our commodity derivative instruments at December 31, 2012 by approximately $53 million to a net liability of $34 million. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Actual gains or losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2012 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

Derivative Instruments Entered Into Subsequent to December 31, 2012

Subsequent to December 31, 2012, through February 21, 2013, we entered into the following derivative instruments:

Commodity Swaps

	Natural Gas (NYMEX HH)	
Swap Term	Bbtu Per Day	Weighted Average Hedged Price per MMBtu
Calendar 2014[(1)]	40	$4.19

(1) In connection with entering into these natural gas swaps with premium hedged prices, we amended the terms of existing oil swaptions with the counterparties for Calendar 2014 covering 2,000 barrels per day, changing the hedged price per barrel from $110.00 to $100.00.

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Interest Rate Risk

We periodically enter into interest rate derivative agreements in an attempt to manage the mix of fixed and floating interest rates within our debt portfolio. As of December 31, 2012, we had entered into the following fixed-to-floating interest rate swaps:

Interest Rate Swaps

Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate	Fair Value (In Thousands)
January 2013 - February 2014	$500,000	1 month LIBOR + 5.89%	8.50%	$13,060

The estimated fair value at December 31, 2012 of all our interest rate derivative instruments based on various inputs, including published forward rates, was an asset of approximately $13 million.

Due to the volatility of interest rates, the estimated fair values of our interest rate derivative instruments are subject to fluctuations from period to period. For example, a hypothetical 10% increase in the forward 1-month LIBOR interest rates used to calculate the fair values of our interest rate derivative instruments at December 31, 2012 would decrease the net fair value of our interest rate derivative instruments at December 31, 2012 by approximately $.1 million. Actual gains or losses recognized related to our interest rate derivative instruments will likely differ from those estimated at December 31, 2012 and will depend exclusively on the future 1-month LIBOR interest rates.

Derivative Fair Value Reconciliation

The table below sets forth the changes that occurred in the fair values of our derivative contracts during the year ended December 31, 2012, beginning with the fair value of our derivative contracts on December 31, 2011. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Due to the volatility of oil, natural gas, and NGL prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. Actual gains and losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2012 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

	Fair Value of Derivative Contracts		
	Commodity	Interest Rate	Total
	(In Thousands)		
As of December 31, 2011	$50,543	$20,556	$71,099
Net increase in fair value	68,791	3,856	72,647
Net contract gains recognized	(100,420)	(11,352)	(111,772)
As of December 31, 2012	$18,914	$13,060	$31,974

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Interest Rates on Borrowings

The following table presents principal amounts and related interest rates by year of maturity for our bank credit facility and senior notes at December 31, 2012:

	2013	2014[1]	2016	2019	2020	Total
	(Dollar Amounts in Thousands)					
Bank credit facility:						
Borrowings outstanding	$—	$—	$65,000	$—	$—	$65,000
Interest rate[2]	—	—	2.12 %	—	—	2.12 %
Senior notes:						
Principal	$12	$300,000	$—	$1,000,000	$500,000	$1,800,012
Fixed interest rate	7.00 %	8.50 %	—	7.25 %	7.50 %	7.53 %
Effective interest rate[3]	7.49 %	9.47 %	—	7.24 %	7.50 %	7.69 %

(1) On February 15, 2013, we irrevocably called $300 million of 8½% senior notes due 2014 to be redeemed March 17, 2013.
(2) Weighted average interest rate as of December 31, 2012.
(3) The effective interest rates on the senior notes differ from the fixed interest rates due to the amortization of related discounts or premiums on the notes.

Foreign Currency Exchange Rate Risk

We conduct business in Italy and South Africa, and thus are subject to foreign currency exchange rate risk on cash flows related primarily to expenses and investing transactions. We have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. Expenditures incurred relative to the foreign concessions held by us outside of North America have been primarily United States dollar-denominated.

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Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Forest Oil Corporation

We have audited the accompanying consolidated balance sheets of Forest Oil Corporation as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Forest Oil Corporation at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Forest Oil Corporation's 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 and our report dated February 22, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 22, 2013

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FOREST OIL CORPORATION
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$1,056	$3,012
Accounts receivable	67,516	79,089
Derivative instruments	40,190	89,621
Other current assets	16,318	38,950
Total current assets	125,080	210,672
Property and equipment, at cost:		
Oil and natural gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $8,237,186 and $6,901,997	1,459,312	1,923,145
Unproved	277,798	675,995
Net oil and natural gas properties	1,737,110	2,599,140
Other property and equipment, net of accumulated depreciation and amortization of $46,908 and $47,989	17,128	51,976
Net property and equipment	1,754,238	2,651,116
Deferred income taxes	14,681	231,116
Goodwill	239,420	239,420
Derivative instruments	8,335	10,422
Other assets	60,108	38,405
	$2,201,862	$3,381,151
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$164,786	$247,880
Accrued interest	23,407	23,259
Derivative instruments	9,347	28,944
Deferred income taxes	14,681	20,172
Current portion of long-term debt	12	—
Other current liabilities	14,092	20,582
Total current liabilities	226,325	340,837
Long-term debt	1,862,088	1,693,044
Asset retirement obligations	56,155	77,898
Derivative instruments	7,204	—
Other liabilities	92,914	76,259
Total liabilities	2,244,686	2,188,038
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 118,245,320 and 114,525,673 shares issued and outstanding	11,825	11,454
Capital surplus	2,541,859	2,486,994
Accumulated deficit	(2,575,994)	(1,287,063)
Accumulated other comprehensive loss	(20,514)	(18,272)
Total shareholders' (deficit) equity	(42,824)	1,193,113
	$2,201,862	$3,381,151

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31, 2012	2011	2010
Revenues:			
Oil, natural gas, and natural gas liquids sales	$605,523	$703,531	$707,692
Interest and other	136	1,026	989
Total revenues	605,659	704,557	708,681
Costs, expenses, and other:			
Lease operating expenses	108,027	99,158	92,394
Production and property taxes	34,249	40,632	43,656
Transportation and processing costs	14,633	13,728	13,242
General and administrative	59,262	65,105	64,886
Depreciation, depletion, and amortization	280,458	219,684	187,973
Ceiling test write-down of oil and natural gas properties	992,404	—	—
Impairment of properties	79,529	—	—
Interest expense	141,831	149,755	149,891
Realized and unrealized gains on derivative instruments, net	(72,646)	(88,064)	(150,132)
Other, net	83,406	17,164	7,339
Total costs, expenses, and other	1,721,153	517,162	409,249
Earnings (loss) from continuing operations before income taxes	(1,115,494)	187,395	299,432
Income tax	173,437	89,135	109,770
Net earnings (loss) from continuing operations	(1,288,931)	98,260	189,662
Net earnings from discontinued operations	—	44,569	37,859
Net earnings (loss)	(1,288,931)	142,829	227,521
Less: net earnings attributable to noncontrolling interest	—	4,987	—
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$(1,288,931)	$137,842	$227,521
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	$(11.21)	$.86	$1.68
Earnings from discontinued operations	—	.35	.33
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$(11.21)	$1.21	$2.01
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	$(11.21)	$.85	$1.67
Earnings from discontinued operations	—	.34	.33
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$(11.21)	$1.19	$2.00
Amounts attributable to Forest Oil Corporation common shareholders:			
Net earnings (loss) from continuing operations	$(1,288,931)	$98,260	$189,662
Net earnings from discontinued operations	—	39,582	37,859
Net earnings (loss)	$(1,288,931)	$137,842	$227,521

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Net earnings (loss)	$(1,288,931)	$142,829	$227,521
Other comprehensive income (loss):			
Foreign currency translation (losses) gains	—	(27,852)	15,153
Defined benefit postretirement plans losses, net of tax	(2,242)	(6,669)	(746)
Total other comprehensive income (loss)	(2,242)	(34,521)	14,407
Total comprehensive income (loss)	(1,291,173)	108,308	241,928
Less: total comprehensive loss attributable to noncontrolling interest	—	(1,330)	—
Total comprehensive income (loss) attributable to Forest Oil Corporation common shareholders	$(1,291,173)	$109,638	$241,928

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In Thousands)

	Common Stock		Capital Surplus	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Forest Oil Corporation Shareholders' Equity (Deficit)	Noncontrolling Interest	Total Shareholders' Equity (Deficit)
	Shares	Amount						
Balances at January 1, 2010	112,337	$11,234	$2,652,689	$(1,652,426)	$67,657	$1,079,154	$—	$1,079,154
Exercise of stock options	458	46	8,653	—	—	8,699	—	8,699
Employee stock purchase plan	64	6	1,431	—	—	1,437	—	1,437
Restricted stock issued, net of forfeitures	889	88	(88)	—	—	—	—	—
Amortization of stock-based compensation	—	—	28,440	—	—	28,440	—	28,440
Other, net	(153)	(15)	(6,856)	—	—	(6,871)	—	(6,871)
Net earnings	—	—	—	227,521	—	227,521	—	227,521
Other comprehensive income					14,407	14,407	—	14,407
Balances at December 31, 2010	113,595	11,359	2,684,269	(1,424,905)	82,064	1,352,787	—	1,352,787
Issuance of Lone Pine Resources Inc. common stock	—	—	112,610	—	(18,007)	94,603	83,572	178,175
Spin-off of Lone Pine Resources Inc.	—	—	(333,568)	—	(54,125)	(387,693)	(82,242)	(469,935)
Exercise of stock options	192	19	2,363	—	—	2,382	—	2,382
Employee stock purchase plan	96	10	1,331	—	—	1,341	—	1,341
Restricted stock issued, net of forfeitures	861	86	(86)	—	—	—	—	—
Amortization of stock-based compensation	—	—	35,449	—	—	35,449	—	35,449

Tax impact of employee stock option exercises	—	—	(9,608)	—	—	(9,608)	—	(9,608)
Other, net	(218)	(20)	(5,766)	—	—	(5,786)	—	(5,786)
Net earnings	—	—	—	137,842	—	137,842	4,987	142,829
Other comprehensive loss	—	—	—	—	(28,204)	(28,204)	(6,317)	(34,521)
Balances at December 31, 2011	114,526	11,454	2,486,994	(1,287,063)	(18,272)	1,193,113	—	1,193,113

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Continued)
(In Thousands)

	Common Stock							
	Shares	Amount	Capital Surplus	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Forest Oil Corporation Shareholders' Equity (Deficit)	Noncontrolling Interest	Total Shareholders' Equity (Deficit)
Balances at December 31, 2011	114,526	11,454	2,486,994	(1,287,063)	(18,272)	1,193,113	—	1,193,113
Common stock issued for acquisition of unproved oil and natural gas properties	2,657	266	36,165	—	—	36,431	—	36,431
Employee stock purchase plan	164	16	1,101	—	—	1,117	—	1,117
Restricted stock issued, net of forfeitures	1,204	121	(121)	—	—	—	—	—
Amortization of stock-based compensation	—	—	21,858	—	—	21,858	—	21,858
Other, net	(306)	(32)	(4,138)	—	—	(4,170)	—	(4,170)
Net loss	—	—	—	(1,288,931)	—	(1,288,931)	—	(1,288,931)
Other comprehensive loss	—	—	—	—	(2,242)	(2,242)	—	(2,242)
Balances at December 31, 2012	118,245	$11,825	$2,541,859	$(2,575,994)	$(20,514)	$(42,824)	$—	$(42,824)

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2012	2011	2010
Operating activities:			
Net earnings (loss)	$(1,288,931)	$142,829	$227,521
Less: net earnings from discontinued operations	—	44,569	37,859
Net earnings (loss) from continuing operations	(1,288,931)	98,260	189,662
Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations:			
Depreciation, depletion, and amortization	280,458	219,684	187,973
Deferred income tax	208,975	58,994	123,671
Unrealized losses (gains) on derivative instruments, net	39,126	(39,087)	(37,920)
Ceiling test write-down of oil and natural gas properties	992,404	—	—
Impairment of properties	79,529	—	—
Stock-based compensation expense	15,074	20,536	18,143
Accretion of asset retirement obligations	6,663	6,082	6,158
Loss (gain) on debt extinguishment, net	36,312	—	(4,576)
Other, net	6,684	8,114	7,039
Changes in operating assets and liabilities:			
Accounts receivable	11,573	23,236	2,640
Other current assets	2,630	14,314	24,136
Accounts payable and accrued liabilities	(21,164)	(6,470)	(62,435)
Accrued interest and other	2,322	(5,566)	(7,766)
Net cash provided by operating activities of continuing operations	371,655	398,097	446,725
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development, acquisition, and leasehold costs	(721,536)	(873,877)	(556,988)
Other fixed assets costs	(9,128)	(6,968)	(5,143)
Proceeds from sales of assets	262,882	121,115	139,077
Net cash used by investing activities of continuing operations	(467,782)	(759,730)	(423,054)
Financing activities:			
Proceeds from bank borrowings	1,244,000	160,000	—
Repayments of bank borrowings	(1,284,000)	(55,000)	—
Issuance of senior notes, net of issuance costs	491,250	—	—
Redemption of senior notes	(330,709)	(285,000)	(152,038)
Proceeds from the exercise of options and from employee stock purchase plan	1,117	3,723	10,136
Change in bank overdrafts	(24,217)	17,116	6,378
Other, net	(3,270)	(14,144)	(6,687)
Net cash provided (used) by financing activities of continuing operations	94,171	(173,305)	(142,211)
Cash flows of discontinued operations:			
Operating cash flows	—	101,292	86,204
Investing cash flows	—	(255,470)	(218,155)
Financing cash flows	—	478,324	1,692
Net cash provided (used) by discontinued operations	—	324,146	(130,259)

Effect of exchange rate changes on cash	—	(3,476)	(277)
Net decrease in cash and cash equivalents	(1,956)	(214,268)	(249,076)
Net (increase) decrease in cash and cash equivalents of discontinued operations	—	(289)	8,370
Net decrease in cash and cash equivalents of continuing operations	(1,956)	(214,557)	(240,706)
Cash and cash equivalents of continuing operations at beginning of year	3,012	217,569	458,275
Cash and cash equivalents of continuing operations at end of year	$1,056	$3,012	$217,569
Cash paid by continuing operations during the year for:			
Interest (net of capitalized amounts)	$130,154	$139,311	$140,856
Income taxes (net of refunded amounts)	(28,253)	31,782	53,748
Non-cash investing activities of continuing operations:			
Increase (decrease) in accrued capital expenditures	$(37,766)	$27,235	$16,405
Common stock issued for acquisition of unproved oil and natural gas properties	36,431	—	—

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012, 2011, and 2010

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids ("NGLs") primarily in the United States. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest holds assets in several exploration and producing areas in the United States and has exploratory and development interests in two other countries. On June 1, 2011, Forest completed an initial public offering of approximately 18% of the common stock of its then wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which held Forest's ownership interests in its Canadian operations. On September 30, 2011, Forest distributed, or spun-off, its remaining 82% ownership in Lone Pine to Forest's shareholders by means of a special stock dividend of Lone Pine shares. See Note 5 for more information regarding the initial public offering and spin-off of Lone Pine. Unless the context indicates otherwise, the terms "Forest," the "Company," "we," "our," and "us," as used in thi Annual Report on Form 10-K, refer to Forest Oil Corporation and its subsidiaries.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of Forest and its consolidated subsidiaries. As a result of the spin-off, Lone Pine's results of operations are reported as discontinued operations. See Note 13 for more information regarding the results of operations of Lone Pine. All intercompany balances and transactions have been eliminated. Certain amounts in prior years' financial statements have been reclassified to conform to the 2012 financial statement presentation.

Assumptions, Judgments, and Estimates

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments, and estimates to determine the reported amounts of assets, liabilities, revenues, and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments, and estimates relate to volumes of oil, natural gas, and natural gas liquids reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitations, and the amount of future capital costs and abandonment obligations used in such calculations, assessing investments in unproved properties and goodwill for impairment, determining the need for and the amount of deferred tax asset valuation allowances, and estimating fair values of financial instruments, including derivative instruments.

Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less and all money market funds with no restrictions on the Company's ability to withdraw money from the funds to be cash equivalents.

Property and Equipment

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During the periods presented, the Company's primary oil and gas operations were conducted in the United States and Canada. Concurrent with the spin-off of Lone Pine on September 30, 2011, the Company no longer has any operations in Canada. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. During the years ended December 31, 2012, 2011, and 2010, Forest capitalized $37.8 million, $46.4 million, and $42.6 million, respectively, of general and administrative costs (including stock-based compensation) related to its continuing operations. Interest costs related to significant unproved properties that are under development are also capitalized to oil and gas properties. During the years ended December 31, 2012, 2011, and 2010, Forest capitalized $7.2 million, $10.3 million, and $11.2 million, respectively, of interest costs attributed to the unproved properties of its continuing operations.

Investments in unproved properties, including capitalized interest costs, are not depleted pending determination of the existence of proved reserves. Unproved properties are assessed at least annually to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, geographic and geologic data obtained relating to the properties, and estimated discounted future net cash flows from the properties. Estimated discounted future net cash flows are based on discounted future net revenues associated with estimated probable and possible reserves, risk adjusted as appropriate. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized, or is reported as a period expense, as appropriate.

During the year ended December 31, 2012, Forest recorded a $66.9 million impairment of its unproved properties in South Africa based on several unsuccessful attempts to sell the properties for an amount that would allow Forest to recover the carrying amount of its investment in these properties. Because Forest has no proved reserves in South Africa, and therefore no costs being amortized, the impairment was reported as a period expense and is included in the Consolidated Statement of Operations within the “Impairment of properties” line item. In December 2012, Forest entered into agreements to dispose of its South African subsidiaries. See Note 2 for more information regarding this planned divestiture.

The Company performs a ceiling test each quarter on a country-by-country basis under the full cost method of accounting. The ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax bases of oil and gas properties. Should the net capitalized costs for a cost center exceed the sum of the components noted above, a ceiling test write-down would be recognized to the extent of the excess capitalized costs.

In 2012, Forest recorded ceiling test write-downs in the United States cost center totaling $957.6 million and the Italian cost center totaling $34.8 million. The United States write-downs resulted primarily from decreases in natural gas and NGL prices. The Italian write-down resulted from Forest concluding that its Italian natural gas reserves could no longer be classified as proved reserves, due to an Italian regional regulatory body’s April 2012 denial of approval of an environmental impact assessment associated with Forest’s proposal to commence natural gas production from wells that Forest drilled and completed in 2007. Forest is currently appealing the region’s denial.

Gain or loss is not recognized on the sale of oil and natural gas properties unless the sale significantly alters the relationship between capitalized costs and estimated proved oil and natural gas reserves attributable to a cost center.

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Depletion of proved oil and natural gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The Company uses its quarter-end reserves estimates to calculate depletion for the current quarter.

Gas gathering assets are depreciated on the units-of-production method whereby the capitalized costs are amortized over the total estimated throughput of the system. Furniture and fixtures, leasehold improvements, computer hardware and software, and other equipment are depreciated on the straight-line method over the estimated useful lives of the assets, which range from three to fifteen years.

Asset Retirement Obligations

Forest records the fair value of a liability for an asset retirement obligation in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the asset retirement obligation is required to be accreted each period to its present value. Capitalized costs are depleted as a component of the full cost pool using the units-of-production method. Forest’s asset retirement obligations consist of costs related to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties.

The following table summarizes the activity for the Company’s asset retirement obligations of its continuing operations for the periods indicated:

	Year Ended December 31,	
	2012	2011
	(In Thousands)	
Asset retirement obligations at beginning of period	$78,938	$73,132
Accretion expense	6,663	6,082
Liabilities incurred	1,412	2,321
Liabilities settled	(5,650)	(3,103)
Disposition of properties	(27,418)	(282)
Revisions of estimated liabilities	4,640	788
Asset retirement obligations at end of period	58,585	78,938
Less: current asset retirement obligations	(2,430)	(1,040)
Long-term asset retirement obligations	$56,155	$77,898

Oil, Natural Gas, and NGL Sales

The Company recognizes revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred, (iii) the Company’s price to the buyer is fixed or determinable and (iv) collectibility is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and an asset is accrued. At December 31, 2012 and 2011, the Company had gas imbalance liabilities of $7.5 million and $7.8 million, respectively, and gas imbalance assets of $6.7 million and $6.9 million, respectively.

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In 2012, sales to two purchasers were approximately 19%, or $117.2 million, and 14%, or $82.1 million, respectively, of the Company's total revenues. In 2011, sales to one purchaser were approximately 22%, or $151.9 million, of the Company's total revenues from continuing operations. In 2010, sales to two purchasers were approximately 20%, or $145.1 million, and 10%, or $73.2 million, respectively, of the Company's total revenues from continuing operations. Forest's revenues from continuing operations are attributable to the United States. Forest believes that the loss of one or more of the Company's current oil, natural gas, and NGL purchasers would not have a material adverse effect on the Company's ability to sell its production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

Accounts Receivable

The components of accounts receivable are as follows:

	December 31,	
	2012	2011
	(In Thousands)	
Oil, natural gas, and NGL sales	$50,679	$58,799
Joint interest billings	5,845	14,451
Tax incentive refunds due from Texas	6,836	6,604
Other	5,619	698
Allowance for doubtful accounts	(1,463)	(1,463)
Total accounts receivable	$67,516	$79,089

Forest's accounts receivable are primarily from purchasers of the Company's oil, natural gas, and NGL sales and from other exploration and production companies which own working interests in the properties that the Company operates. This industry concentration could adversely impact Forest's overall credit risk because the Company's customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Forest's oil, natural gas, and NGL production is sold to various purchasers in accordance with the Company's credit policies and procedures. These policies and procedures take into account, among other things, the creditworthiness of potential purchasers and concentrations of credit risk. Forest generally requires letters of credit or parental guarantees for receivables from parties that are deemed to have sub-standard credit or other financial concerns, unless the Company can otherwise mitigate the perceived credit exposure. Forest routinely assesses the collectibility of all material receivables and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve can be reasonably estimated.

Income Taxes

The Company recognizes deferred tax liabilities and assets for the expected future tax consequences of temporary differences between financial accounting bases and tax bases of assets and liabilities. The tax benefits of tax loss carryforwards and other deferred tax benefits are recorded as an asset to the extent that management assesses the utilization of such assets to be more likely than not. When the future utilization of some portion of the deferred tax asset is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded deferred tax assets.

Earnings (Loss) per Share

Basic earnings (loss) per share is computed using the two-class method by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. The two-class method of computing earnings (loss) per share is required to be used since Forest has participating securities. The two-class method is an earnings allocation formula that determines earnings (loss) per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation

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rights in undistributed earnings. Holders of restricted stock issued under Forest's stock incentive plans have the right to receive non-forfeitable cash and certain non-cash dividends, participating on an equal basis with common stock. Holders of phantom stock units issued to directors under Forest's stock incentive plans also have the right to receive non-forfeitable cash and certain non-cash dividends, participating on an equal basis with common stock, while phantom stock units issued to employees do not participate in dividends. Stock options issued under Forest's stock incentive plans do not participate in dividends. Performance units issued under Forest's stock incentive plans do not participate in dividends in their current form. Holders of performance units participate in dividends paid during the performance units' vesting period only after the performance units vest and common shares are deliverable under the terms of the performance unit awards. Performance units may vest with no common shares being deliverable, depending on Forest's shareholder return over the performance units' vesting period in relation to the shareholder returns of specified peers. See Note 6 for more information on Forest's stock-based incentive awards. In summary, restricted stock issued to employees and directors and phantom stock units issued to directors are participating securities, and earnings are allocated to both common stock and these participating securities under the two-class method. However, these participating securities do not have a contractual obligation to share in Forest's losses. Therefore, in periods of net loss, none of the loss is allocated to these participating securities.

Diluted earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period, increasing the denominator to include the number of additional common shares that would have been outstanding if the dilutive potential common shares (e.g. stock options, unvested restricted stock, unvested phantom stock units that may be settled in shares, and unvested performance units) had been issued. Additionally, the numerator is also adjusted for certain contracts that provide the issuer or holder with a choice between settlement methods. Diluted earnings (loss) per share is computed using the more dilutive of the treasury stock method, the contingently issuable share method, or the two-class method, depending on the security. Under the treasury stock method, the dilutive effect of options, unvested restricted stock, and unvested phantom stock units is calculated by assuming common shares are issued for these securities at the beginning of the period, with the proceeds from exercise assumed to be used to purchase common shares at the average market price for the period, and the incremental shares (the difference between the number of shares assumed issued and the number of shares assumed purchased) included in the denominator of the diluted earnings (loss) per share computation. Under the contingently issuable share method, the number of contingently issuable shares pursuant to the outstanding performance units are included in the denominator of the calculation of diluted earnings (loss) per share based on the number of shares, if any, that would be issuable if the end of the reporting period were the end of the contingency period and if the result would be dilutive. Under the two-class method, the dilutive effect of non-participating potential common shares is determined and undistributed earnings are reallocated between common shares and participating securities. No potential common shares are included in the computation of any diluted per share amount when a net loss exists, as was the case for the year ended December 31, 2012. Unvested restricted stock grants were not included in the calculations of diluted earnings per share for the years ended December 31, 2011 and 2010 as their inclusion would have an antidilutive effect.

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The following reconciles net earnings (loss) as reported in the Consolidated Statements of Operations to net earnings (loss) used for calculating basic and diluted earnings (loss) per share for the periods presented.

	Year Ended December 31,								
	2012			2011			2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In Thousands)								
Net earnings (loss)	$(1,288,931)	$—	$(1,288,931)	$98,260	$44,569	$142,829	$189,662	$37,859	$227,521
Net earnings attributable to noncontrolling interest	—	—	—	—	(4,987)	(4,987)	—	—	—
Net earnings attributable to participating securities	—	—	—	(2,037)	(821)	(2,858)	(3,736)	(746)	(4,482)
Net earnings (loss) attributable to common stock for basic earnings (loss) per share	(1,288,931)	—	(1,288,931)	96,223	38,761	134,984	185,926	37,113	223,039
Adjustment for liability classified stock-based compensation awards	—	—	—	—	(707)	(707)	—	500	500
Net earnings (loss) for diluted earnings (loss) per share	$(1,288,931)	$—	$(1,288,931)	$96,223	$38,054	$134,277	$185,926	$37,613	$223,539

The following reconciles basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the periods presented.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Weighted average common shares outstanding during the period for basic earnings (loss) per share	114,958	111,690	110,809
Dilutive effects of potential common shares	—	1,178	689
Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares, for diluted earnings (loss) per share	114,958	112,868	111,498

Stock-Based Compensation

Compensation cost is measured at the grant date based on the fair value of the awards (stock options, restricted stock, performance units, employee stock purchase plan rights) or is measured at the reporting date based on the current stock price (phantom stock units), and is recognized on a straight-line basis over the requisite service period (usually the vesting period).

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value, other than the derivative instruments that meet the normal purchases and sales exception. The Company has not elected to designate its derivative instruments as hedges and, therefore, records all changes in fair value of its derivative instruments through earnings, with such changes reported in a single line item in the Consolidated Statements of Operations together with realized gains and losses on the derivative instruments.

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Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2012 and 2011 totaled $27.0 million and $25.0 million, respectively, and are being amortized over the life of the respective debt instruments.

Inventory

Inventories, which are carried at average cost with adjustments made from time to time to recognize, as appropriate, any reductions in value, were comprised of $4.2 million and $10.1 million of materials and supplies as of December 31, 2012 and 2011, respectively. The Company's materials and supplies inventory, which is acquired for use in future drilling operations, is primarily comprised of items such as tubing and casing.

Goodwill

The Company is required to perform an annual impairment test of goodwill in lieu of periodic amortization. The Company performs its annual goodwill impairment test in the second quarter of the year. In addition, the Company tests goodwill for impairment if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The impairment test requires the Company to estimate the fair value of the reporting unit to which goodwill has been assigned and, in some cases, the fair values of the assets and liabilities assigned to the reporting unit. Although the Company bases its fair value estimates on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. The Company had no goodwill impairments for the years ended December 31, 2012, 2011, and 2010.

Comprehensive Income (Loss)

Comprehensive income (loss) is a term used to refer to net earnings (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net earnings (loss). Items included in the Company's other comprehensive income (loss) during the last three years are net foreign currency gains and losses related to the translation of the assets and liabilities of Lone Pine's Canadian operations prior to the spin-off of Lone Pine on September 30, 2011, and defined benefit postretirement plan losses.

The components of other comprehensive income (loss), both before-tax and net-of-tax, for the years ended December 31, 2012, 2011, and 2010 are as follows:

	Before-Tax	Tax (Expense) / Benefit	Net-of-Tax
	(In Thousands)		
Year Ended December 31, 2012:			
Defined benefit postretirement plans - net loss	$(2,036)	$(206)	$(2,242)
Other comprehensive loss	$(2,036)	$(206)	$(2,242)
Year Ended December 31, 2011:			
Defined benefit postretirement plans - net loss	$(10,417)	$3,748	$(6,669)
Foreign currency translation losses	(27,852)	—	(27,852)
Other comprehensive loss	$(38,269)	$3,748	$(34,521)
Year Ended December 31, 2010:			
Defined benefit postretirement plans - net loss	$(1,221)	$475	$(746)
Foreign currency translation gains	15,153	—	15,153
Other comprehensive income	$13,932	$475	$14,407

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The components of accumulated other comprehensive income (loss) attributable to Forest Oil Corporation common shareholders for the years ended December 31, 2012, 2011, and 2010 are as follows:

	Foreign Currency Translation	Defined Benefit Postretirement Plans	Accumulated Other Comprehensive Income (Loss)
	(In Thousands)		
Balance at December 31, 2009	$78,514	$(10,857)	$67,657
Other comprehensive income (loss)	15,153	(746)	14,407
Balance at December 31, 2010	93,667	(11,603)	82,064
Other comprehensive loss	(21,535)	(6,669)	(28,204)
Changes in ownership interest in Lone Pine Resources	(72,132)	—	(72,132)
Balance at December 31, 2011	—	(18,272)	(18,272)
Other comprehensive loss	—	(2,242)	(2,242)
Balance at December 31, 2012	$—	$(20,514)	$(20,514)

Impact of Recently Issued Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities ("ASU 2011-11"), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement. In January 2013, the FASB issued ASU 2013-01, Balance Sheet (Topic 210) Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which limits the scope of ASU No. 2011-11 to derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions. ASU 2011-11 was issued in order to facilitate comparison of financial statements prepared under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards by requiring enhanced disclosures, but does not change existing U.S. GAAP, which permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The adoption of this authoritative guidance will not have an impact on Forest's financial position or results of operations, but will require Forest to make additional disclosures regarding its derivative instruments.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220) Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income ("ASU 2013-02"). ASU 2013-02 does not change the current requirements for reporting net earnings or other comprehensive income in financial statements. However, it requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net earnings, but only if the amount reclassified is required under U.S. GAAP to be reclassified to net earnings in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net earnings, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This authoritative guidance is effective prospectively for annual reporting periods beginning after December 15, 2012, and interim periods within those annual periods. The adoption of this authoritative guidance will not have an impact on Forest's financial position or results of operations. Forest is currently evaluating the impact adoption of this authoritative guidance may have on its disclosures.

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(2) PROPERTY AND EQUIPMENT:

Net property and equipment consists of the following as of the dates indicated:

	December 31, 2012	2011
	(In Thousands)	
Oil and gas properties:		
Proved	$9,696,498	$8,825,142
Unproved	277,798	675,995
Accumulated depletion	(8,237,186)	(6,901,997)
Net oil and gas properties	1,737,110	2,599,140
Other property and equipment:		
Gas gathering, furniture and fixtures, computer hardware and software, and other equipment	64,036	99,965
Accumulated depreciation and amortization	(46,908)	(47,989)
Net other property and equipment	17,128	51,976
Total net property and equipment(1)	$1,754,238	$2,651,116

(1) At December 31, 2011, $98.7 million of the Company’s total net property and equipment was located in foreign countries. This balance was written off during 2012 when the South African properties were impaired and the Italian natural gas reserves were reclassified from proved to probable, causing a full ceiling test write-down of the Italian cost center, both of which are discussed in Note 1.

The following table sets forth a summary as of December 31, 2012 of Forest’s unproved properties, all of which are located in the United States, by the year in which such property costs were incurred:

	Total	2012	2011	2010	2009 and Prior
	(In Thousands)				
Acquisition costs	$232,176	$14,136	$46,729	$15,530	$155,781
Exploration costs	45,622	37,614	3,940	641	3,427
Total unproved oil and gas properties	$277,798	$51,750	$50,669	$16,171	$159,208

The majority of the unproved oil and gas property costs, which are not subject to depletion, relate to oil and gas property acquisitions and leasehold acquisition costs as well as work-in-progress on various projects. The Company expects that substantially all of its unproved property costs as of December 31, 2012 will be reclassified to proved properties within ten years.

Divestitures

In August 2012, the Company entered into an agreement to sell the majority of its East Texas natural gas gathering assets for $34.0 million in cash, subject to customary purchase price adjustments. This transaction closed on October 31, 2012, resulting in Forest receiving net proceeds of $28.8 million. Forest can also earn up to $9.0 million of additional performance payments contingent on future activity including the number of additional wells drilled by Forest and connected to the buyer’s gathering facilities. During the first month of 2013, Forest earned and received a performance payment of $1.0 million. In conjunction with the sale, Forest entered into a ten-year natural gas gathering agreement with the buyer under which Forest will pay market-based gathering rates and commit the production from its existing and future operated wells located within five miles of the gathering system as it was configured at the time of sale. During the third quarter of 2012, these assets were written down to their estimated fair

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value less cost to sell, resulting in a $12.7 million impairment charge, which is included in the Consolidated Statement of Operations within the “Impairment of properties” line item. Since there will be a continuation of cash flows between Forest and the disposed component by way of the natural gas gathering agreement, these assets did not qualify for discontinued operations reporting.

In October 2012, Forest entered into an agreement to sell all of its oil and natural gas properties located in South Louisiana for $220.0 million in cash. This transaction closed on November 16, 2012 and was subject to customary purchase price adjustments, resulting in Forest receiving net proceeds of $208.4 million.

In December 2012, Forest entered into an agreement with a third party whereby Forest will receive $9.1 million in exchange for Forest abandoning its Exploration Right covering Block 2C in South Africa. The $9.1 million is payable in two tranches: a first payment of $2.8 million is to be received upon acceptance from South Africa of the abandonment and a second payment of $6.3 million is to be received in the event that the third party is successful in being awarded a new Exploration Right in respect of an area encompassing all or part of Forest’s abandoned Block 2C. As of December 31, 2012, neither event had occurred and, accordingly, neither event is reflected in the Consolidated Financial Statements.

Forest also entered into a separate agreement in December 2012 to sell its South African subsidiary which holds a Production Right related to Block 2A in South Africa. The consideration for this sale is payable in several steps, subject to various contingencies. Upon signing the sale agreement, Forest received a nonrefundable cash payment of $.7 million. Following approval of the sale by the Minister of Mineral Resources for the government of the Republic of South Africa, Forest will receive a payment of $1.0 million. If such approval is not received, closing on the sale will not occur. If closing occurs, Forest may receive further payments, as defined in the agreement. Forest recognized $.6 million of the initial consideration received, net of estimated selling costs, as other income within the “Other, net” line item in the Consolidated Statement of Operations.

During the year ended December 31, 2012, Forest also sold miscellaneous oil and natural gas properties for proceeds of $25.6 million. During the years ended December 31, 2011 and 2010, Forest sold various U.S. oil and natural gas properties for total proceeds of $121.0 million and $75.9 million respectively. During 2010, Forest also entered into sale-leaseback transactions involving drilling rigs, receiving $63.1 million in total proceeds.

Divestitures - Subsequent Event

In January 2013, Forest entered into an agreement to sell all of its oil and natural gas properties located in South Texas, excluding its Eagle Ford Shale oil properties, for $325.0 million in cash. This transaction closed on February 15, 2013 and was subject to customary purchase price adjustments, resulting in Forest receiving net proceeds of $307.2 million.

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(3) DEBT:

The components of debt are as follows:

	December 31, 2012			December 31, 2011		
	Principal	Unamortized Premium (Discount)	Total	Principal	Unamortized Premium (Discount)	Total
	(In Thousands)					
Credit facility	$65,000	$—	$65,000	$105,000	$—	$105,000
7% senior subordinated notes due 2013	12	—	12	12	—	12
8½% senior notes due 2014	300,000	(3,277)	296,723	600,000	(12,389)	587,611
7¼% senior notes due 2019	1,000,000	365	1,000,365	1,000,000	421	1,000,421
7½% senior notes due 2020	500,000	—	500,000	—	—	—
Total debt	1,865,012	(2,912)	1,862,100	1,705,012	(11,968)	1,693,044
Less: current portion of long-term debt(1)	(12)	—	(12)	—	—	—
Long-term debt	$1,865,000	$(2,912)	$1,862,088	$1,705,012	$(11,968)	$1,693,044

(1) Due in June 2013.

Bank Credit Facility

On June 30, 2011, the Company entered into the Third Amended and Restated Credit Agreement (the “Credit Facility”) with a syndicate of banks led by JPMorgan Chase Bank, N.A. (the “Administrative Agent”) consisting of a $1.5 billion credit facility maturing in June 2016. The size of the Credit Facility may be increased by $300.0 million, to a total of $1.8 billion, upon agreement between the applicable lenders and Forest.

Forest’s availability under the Credit Facility is governed by a borrowing base. As of December 31, 2012, the borrowing base under the Credit Facility was $1.07 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of Forest’s oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders’ customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. A lowering of the borrowing base could require Forest to repay indebtedness in excess of the borrowing base in order to cover the deficiency. The last scheduled semi-annual redetermination of the borrowing base occurred in October 2012 and resulted in a $50.0 million reduction to the borrowing base. The next scheduled semi-annual redetermination of the borrowing base will occur on or about May 1, 2013. In addition to the scheduled semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during a calendar year, to have the borrowing base redetermined.

The borrowing base is also subject to automatic adjustments if certain events occur, such as if Forest or any of its Restricted Subsidiaries (as defined in the Credit Facility) issue senior unsecured notes, in which case the borrowing base will immediately be reduced by an amount equal to 25% of the stated principal amount of such issued senior notes, excluding any senior unsecured notes that Forest or any of its Restricted Subsidiaries may issue to refinance senior notes that were outstanding on June 30, 2011. This was the case in September 2012 in connection with the issuance of senior unsecured notes, when the borrowing base was reduced by $50.0 million. The borrowing base is also subject to automatic adjustment if Forest or any of its Restricted Subsidiaries sell oil and natural gas properties included in the borrowing base, as applicable, having a fair market value in excess of 10% of the borrowing base then in effect. In this case, the borrowing base will be reduced by an amount either (i) equal to the percentage of the borrowing base attributable to the sold properties, as determined by the Administrative Agent, or (ii) if none of the borrowing base is attributable to the sold properties, a value agreed upon by Forest and the required lenders. The sale of Forest's South Louisiana properties, discussed in Note 2, resulted in an $80.0 million reduction to the borrowing base when the transaction closed in November 2012. The February 2013 sale of Forest's

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South Texas properties, discussed in Note 2, resulted in a $170.0 million reduction to the borrowing base, which reduced the borrowing base to $900.0 million effective February 15, 2013.

The Credit Facility is collateralized by Forest's assets. Under the Credit Facility, Forest is required to mortgage and grant a security interest in 75% of the present value of the estimated proved oil and gas properties and related assets. If Forest's corporate credit ratings issued by Moody's and S&P meet pre-established levels, the security requirements would cease to apply and, at Forest's request, the banks would release their liens and security interest on Forest's properties.

Borrowings under the Credit Facility bear interest at one of two rates as may be elected by the Company. Borrowings bear interest at:

(i) the greatest of (a) the prime rate announced by JPMorgan Chase Bank, N.A., (b) the federal funds effective rate from time to time plus ½ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by Forest) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or

(ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 basis points, depending on borrowing base utilization.

The Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also includes a financial covenant. The Credit Facility provides that Forest will not permit its ratio of total debt outstanding to EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.5 to 1.0 at any time.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated. Bankruptcy and insolvency events with respect to Forest or certain of its subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. Subject to notice and cure periods, certain events of default under the Credit Facility will result in acceleration of the indebtedness under the Credit Facility at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the Credit Facility (including the financial covenant), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the Credit Facility.

Of the $1.5 billion total nominal amount under the Credit Facility, JPMorgan and ten other banks hold approximately 68% of the total commitments. With respect to the other 32% of the total commitments, no single lender holds more than 3.3% of the total commitments. Commitment fees accrue on the amount of unutilized borrowing base. If borrowing base utilization is greater than 50%, commitment fees are 50 basis points of the unutilized amount, and if borrowing base utilization is 50% or less, commitment fees are 35 basis points of the unutilized amount.

At December 31, 2012, there were outstanding borrowings of $65.0 million under the Credit Facility at a weighted average interest rate of 2.1% and Forest had used the Credit Facility for $1.6 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.0 billion. At December 31, 2011, there were outstanding borrowings of $105.0 million under the Credit Facility at a weighted average interest rate of 2.1% and Forest had used the Credit Facility for $2.1 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.1 billion.

8½% Senior Notes Due 2014

On February 17, 2009, Forest issued $600.0 million in principal amount of 8½% senior notes due 2014 (the "8½% Notes") at 95.15% of par for net proceeds of $559.8 million, after deducting initial purchaser discounts. The 8½% Notes are redeemable, at the Company's option, in whole or in part, at any time at the principal amount, plus accrued interest, and a make-whole premium. In October 2012, Forest redeemed $300.0 million of the 8½% Notes at 110.24% of par, recognizing a loss of $36.3 million upon redemption, using proceeds from the issuance of $500.0 million in principal amount of 7½% senior notes due 2020. Due to the amortization of the discount, the effective interest rate on the 8½% Notes is 9.47%. Interest on the 8½% Notes is payable semiannually on February 15 and August 15. On February 15, 2013, Forest irrevocably called the remaining $300.0 million of 8½% Notes outstanding to be redeemed on March 17, 2013 using cash on hand and borrowings under the Credit Facility.

7¼% Senior Notes Due 2019

On June 6, 2007, Forest issued $750.0 million in principal amount of 7¼% senior notes due 2019 (the "7¼% Notes") at par for net proceeds of $739.2 million, after deducting initial purchaser discounts, and on May 22, 2008, Forest issued an additional $250.0 million in principal amount of 7¼% Notes at 100.25% of par for net proceeds of $247.2 million, after deducting initial purchaser discounts. Due to the amortization of the premium, the effective interest rate on the 7¼% Notes is 7.24%. Interest on the 7¼% Notes is payable semiannually on June 15 and December 15.

The 7¼% Notes are redeemable, at Forest's option, at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest, if redeemed during the twelve-month period beginning on June 15 of the years indicated below:

2012	103.625	%
2013	102.417	%
2014	101.208	%
2015 and thereafter	100.000	%

7½% Senior Notes Due 2020

On September 17, 2012, Forest issued $500.0 million in principal amount of 7½% senior notes due 2020 (the "7½% Notes") at par for net proceeds of $491.3 million, after deducting initial purchaser discounts. Net proceeds from the 7½% Notes were used to temporarily reduce outstanding borrowings under the Credit Facility until $300.0 million in principal amount of the 8½% Notes could be redeemed in October 2012 (after the required notice of redemption period elapsed). Interest on the 7½% Notes is payable semiannually on March 15 and September 15.

The 7½% Notes are redeemable, at Forest's option, at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest, if redeemed during the twelve-month period beginning on September 15 of the years indicated below:

2016	103.750	%
2017	101.875	%
2018 and thereafter	100.000	%

Forest may also redeem the 7½% Notes, in whole or in part, at any time prior to September 15, 2016, at a price equal to the principal amount plus a make-whole premium, calculated using the applicable Treasury yield plus 0.5%, plus accrued but unpaid interest. In addition, prior to September 15, 2015, Forest may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the 7½% Notes with the net proceeds of certain equity offerings at 107.5% of the principal amount of the 7½% Notes, plus any accrued but unpaid interest, if at least 65% of the aggregate principal amount of the 7½% Notes remains outstanding after such redemption and the redemption occurs within 120 days of the date of the closing of such equity offering.

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Principal Maturities

Principal maturities of Forest's debt at December 31, 2012 are as follows:

	Principal Maturities (In Thousands)
2013	$12
2014	300,000
2015	—
2016	65,000
2017	—
Thereafter	1,500,000

(4) INCOME TAXES:

Income Tax Provision

The table below sets forth the provision for income taxes attributable to continuing operations for the periods presented.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Current:			
Federal	$(34,733)	$(201)	$(16,393)
Foreign	—	28,921	—
State	(805)	1,421	2,492
	(35,538)	30,141	(13,901)
Deferred:			
Federal	202,552	56,482	121,111
State	6,423	2,512	2,560
	208,975	58,994	123,671
Total income tax	$173,437	$89,135	$109,770

Earnings (loss) from continuing operations before income taxes consists of the following for the periods presented:

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
United States Federal	$(1,013,801)	$188,421	$301,349
Foreign	(101,693)	(1,026)	(1,917)
	$(1,115,494)	$187,395	$299,432

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A reconciliation of reported income tax attributable to continuing operations to the amount of income tax that would result from applying the United States federal statutory income tax rate to pretax earnings from continuing operations is as follows:

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Federal income tax at 35% of earnings before income taxes and discontinued operations	$(390,423)	$65,947	$105,472
State income taxes, net of federal income tax benefits	(11,211)	2,214	3,526
Change in valuation allowance	575,570	—	—
Canadian dividend tax, net of U.S. tax benefit	—	18,460	—
Effect of federal, state, and foreign tax on permanent differences	3,026	4,025	4,030
Other	(3,525)	(1,511)	(3,258)
Total income tax	$173,437	$89,135	$109,770

Net Deferred Tax Assets and Liabilities

The components of net deferred tax assets and liabilities at December 31, 2012 and 2011 are as follows:

	December 31,	
	2012	2011
	(In Thousands)	
Deferred tax assets:		
Property and equipment[(1)]	$353,352	$101,299
Accrual for postretirement benefits	3,134	11,545
Stock-based compensation accruals	10,748	7,921
Net operating loss carryforwards	157,103	60,965
Alternative minimum tax credit carryforward	49,409	54,776
Other	32,278	8,418
Total gross deferred tax assets	606,024	244,924
Less valuation allowance	(575,570)	—
Net deferred tax assets	30,454	244,924
Deferred tax liabilities:		
Unrealized gains on derivative contracts, net	(17,429)	(25,713)
Amortization of deferred gain on rig sales	(10,472)	(8,267)
Other	(2,553)	—
Total gross deferred tax liabilities	(30,454)	(33,980)
Net deferred tax assets	$—	$210,944

(1) Includes deferred tax assets of $28.3 million related to Italy and South Africa as of December 31, 2012.

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The net deferred tax assets and liabilities are reflected in the Consolidated Balance Sheets as follows:

	December 31,	
	2012	2011
	(In Thousands)	
Current deferred tax liabilities	$(14,681)	$(20,172)
Non-current deferred tax assets	14,681	231,116
Net deferred tax assets	$—	$210,944

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2012 were approximately $440.3 million, with $32.2 million of NOLs limited under Section 382 of the Internal Revenue Code scheduled to expire in 2019 and the remaining scheduled to expire after 2030.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2008. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2008. However, the Company has utilized, and will continue to utilize, NOLs (including NOLs of acquired businesses) in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1999, but are potentially subject to adjustment by the federal tax authorities in the tax year in which they are utilized. Thus, the Company's earliest U.S. federal income tax return that is closed to potential audit adjustment is the tax year ending December 31, 1998.

Alternative Minimum Tax Credits

The Alternative Minimum Tax credit carryforward available to reduce future U.S. federal regular taxes equaled an aggregate amount of $49.4 million at December 31, 2012, which can be carried forward indefinitely.

Accounting for Uncertainty in Income Taxes

The table below sets forth the reconciliation of the beginning and ending balances of the total amounts of unrecognized tax benefits. The Company records interest accrued related to unrecognized tax benefits in interest expense and penalties in other expense, to the extent they apply. The Company does not expect a material amount of unrecognized tax benefits to reverse in the next twelve months.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Gross unrecognized tax benefits at beginning of period	$2,829	$3,345	$2,665
Increases as a result of tax positions taken during a prior period	—	—	1,078
Decreases as a result of tax positions taken during a prior period	(1,970)	(516)	(398)
Gross unrecognized tax benefits at end of period	$859	$2,829	$3,345

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Income Tax Receivables

The table below sets forth income tax receivables as of the dates indicated.

	December 31,	
	2012	2011
	(In Thousands)	
Current income tax receivable(1)	$—	$16,481
Non-current income tax receivable(2)	20,651	—
	$20,651	$16,481

(1) Included in “Other current assets” in the Consolidated Balance Sheets.
(2) Included in “Other assets” in the Consolidated Balance Sheets.

(5) SHAREHOLDERS’ EQUITY:

Common Stock

At December 31, 2012, the Company had 200.0 million shares of common stock, par value $.10 per share, authorized and 118.2 million shares issued and outstanding.

In February 2012, the Company issued 2.7 million shares of common stock, valued at approximately $36.4 million, as partial consideration pursuant to a lease purchase agreement whereby Forest acquired leases on unproved oil and natural gas properties in the Permian Basin in Texas.

Preferred Stock

Forest has 10.0 million shares of preferred stock, par value $.01 per share, authorized under its Articles of Incorporation. The preferred stock is classified into two classes, Senior Preferred Stock and Junior Preferred Stock, each of which shall be issuable in one or more series. Subject to any limitation prescribed by law, the number of shares in each series and the designation and relative rights, preferences, and limitations of each series shall be fixed by the Board of Directors of Forest. The class of Senior Preferred Stock consists of 7.4 million shares and the class of Junior Preferred Stock consists of 2.7 million shares. No preferred stock is issued or outstanding.

Lone Pine Resources Inc.

On June 1, 2011, Forest completed an initial public offering of approximately 18% of the common stock of its then wholly-owned subsidiary, Lone Pine, which held Forest’s ownership interests in its Canadian operations. In May 2011, as part of a corporate restructuring in anticipation of Lone Pine’s initial public offering, Lone Pine Resources Canada Ltd. (“LPR Canada”), Forest’s former Canadian subsidiary, declared a stock dividend to Forest immediately before Forest’s contribution of LPR Canada to Lone Pine, with such stock dividend resulting in Forest incurring a dividend tax payable to Canadian federal tax authorities of $28.9 million, which Forest paid in June 2011. This dividend tax is classified within the “Income tax” line item in the Consolidated Statement of Operations. The net proceeds from the initial public offering received by Lone Pine, after deducting underwriting discounts and commissions and offering expenses, were approximately $178.2 million. Lone Pine used the net proceeds to pay $29.2 million to Forest as partial consideration for Forest’s contribution to Lone Pine of Forest’s direct and indirect interests in its Canadian operations. Additionally, Lone Pine used the remaining net proceeds and borrowings under Lone Pine’s credit facility to repay Lone Pine’s outstanding indebtedness owed to Forest, consisting of a note payable, intercompany advances, and accrued interest, of $400.5 million. On September 30, 2011, Forest distributed, or spun-off, its remaining 82% ownership in Lone Pine to Forest’s shareholders, by means of a special stock dividend whereby Forest shareholders received .61248511 of a share of Lone Pine common stock for every share of Forest common stock held. In accordance with applicable authoritative accounting guidance, Forest accounted for the spin-off based on the carrying value of Lone Pine.

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The table below sets forth the effects of changes in Forest's ownership interest in Lone Pine on Forest's equity, during the 2011 period in which Forest had an ownership interest in Lone Pine up to its spin-off on September 30, 2011.

	Nine Months Ended September 30, 2011 (In Thousands)
Net earnings attributable to Forest Oil Corporation common shareholders	$118,375
Transfers from (to) the noncontrolling interest:	
Increase in Forest Oil Corporation's capital surplus for sale of 15 million Lone Pine Resources Inc. common shares	112,610
Decrease in Forest Oil Corporation's capital surplus for spin-off of 70 million Lone Pine Resources Inc. common shares	(333,568)
Change from net earnings attributable to Forest Oil Corporation common shareholders and transfers from (to) noncontrolling interest	$(102,583)

Rights Agreement

In October 1993, the Board of Directors of Forest adopted a shareholders' rights plan and entered into a Rights Agreement (the "1993 Agreement"), which was amended and supplemented in October 2003 by the First Amended and Restated Rights Agreement (taken together with the 1993 Agreement, the "Rights Agreement"). Under the Rights Agreement, one Preferred Share Purchase Right (the "Rights") is issued for each outstanding share of the Company's common stock. The Rights expire on October 29, 2013, unless earlier exchanged or redeemed. The Rights entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120 and are exercisable only if a person or group acquires 20% or more of the Company's common stock or announces a tender offer that would result in ownership by a person or group of 20% or more of the common stock.

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(6) STOCK-BASED COMPENSATION:

Stock-based Compensation Plans

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the “2001 Plan”) and in 2007, the Company adopted the Forest Oil Corporation 2007 Stock Incentive Plan (the “2007 Plan,” and together with the 2001 Plan, the “Stock-based Compensation Plans”) under which qualified and non-qualified stock options, restricted stock, performance units, phantom stock units, and other awards may be granted to employees, consultants, and non-employee directors. The aggregate number of shares of common stock that the Company may issue under the 2007 Plan may not exceed 8.7 million shares. As of December 31, 2012, the Company had 3.2 million shares available to be issued under the 2007 Plan. The aggregate number of shares of common stock that the Company could issue under the 2001 Plan was 5.0 million, of which there are no remaining shares to be issued at December 31, 2012.

Compensation Costs

The table below sets forth stock-based compensation related to Forest’s continuing operations for the years ended December 31, 2012, 2011, and 2010, and the remaining unamortized amounts and weighted average amortization period as of December 31, 2012.

	Stock Options	Restricted Stock	Performance Units	Phantom Stock Units	Total[(1)]
	(In Thousands)				
Year ended December 31, 2012:					
Total stock-based compensation costs	$—	$14,621	$6,838	$859	$22,318
Less: stock-based compensation costs capitalized	—	(5,219)	(1,565)	(569)	(7,353)
Stock-based compensation costs expensed	$—	$9,402	$5,273	$290	$14,965
Unamortized stock-based compensation costs as of December 31, 2012[(2)]	$—	$16,588	$7,723	$6,795	$31,106
Weighted average amortization period remaining as of December 31, 2012	—	1.8 years	1.8 years	2.3 years	1.9 years
Year ended December 31, 2011:					
Total stock-based compensation costs	$1,536	$30,234	$3,178	$156	$35,104
Less: stock-based compensation costs capitalized	(663)	(13,113)	(957)	(134)	(14,867)
Stock-based compensation costs expensed	$873	$17,121	$2,221	$22	$20,237
Year ended December 31, 2010:					
Total stock-based compensation costs	$563	$25,377	$1,907	$3,129	$30,976
Less: stock-based compensation costs capitalized	(241)	(9,492)	(469)	(1,010)	(11,212)
Stock-based compensation costs expensed	$322	$15,885	$1,438	$2,119	$19,764

(1) The Company also maintains an employee stock purchase plan (which is not included in the table) under which $.4 million, $.5 million, and $.5 million of compensation costs were recognized for the years ended December 31, 2012, 2011, and 2010, respectively.

(2) The unamortized stock-based compensation costs of the phantom stock units are based on the closing price of the Company’s common stock on December 31, 2012.

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Stock Options

The following table summarizes stock option activity in the Stock-based Compensation Plans for the years ended December 31, 2012, 2011, and 2010.

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Options Exercisable
Outstanding at January 1, 2010	1,818,419	$21.26	$7,387	1,722,216
Granted	—	—		
Exercised	(457,974)	18.99	6,027	
Cancelled	(32,750)	36.28		
Outstanding at December 31, 2010	1,327,695	21.67	22,531	1,283,232
Granted	—	—		
Exercised	(29,711)	18.55	331	
Cancelled	(13,273)	25.11		
Spin-off adjustment[2]	673,189			
Outstanding at September 30, 2011	1,957,900	14.29	187	1,957,900
Granted	—	—		
Exercised	(161,834)	11.32	634	
Cancelled	(29,479)	14.86		
Outstanding at December 31, 2011	1,766,587	14.55	2,731	1,766,587
Granted	—	—		
Exercised	—	—	—	
Cancelled	(895,771)	11.33		
Outstanding at December 31, 2012	870,816	$17.86	$—	870,816

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock, as of the date outstanding or exercised, exceeds the exercise price of the option.

(2) In conjunction with the spin-off of Lone Pine, both the number of options outstanding and the option exercise prices were adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans.

Stock options are granted at the fair market value of one share of common stock on the date of grant and have a term of ten years. Options granted to non-employee directors vest immediately and options granted to officers and other employees vest in increments of 25% on each of the first four anniversary dates of the grant.

The following table summarizes information about options outstanding at December 31, 2012:

	Stock Options Outstanding and Exercisable			
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)
$9.70 - 11.09	197,002	0.85	$10.75	$—
11.10 - 13.47	38,676	1.57	12.44	—
13.48 - 13.56	244,070	1.86	13.56	—
13.57 - 24.31	167,978	3.05	20.33	—
24.32 - 27.90	223,090	4.42	27.90	—

$9.70 - 27.90	870,816	2.50	$17.86	$—

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Restricted Stock, Performance Units, and Phantom Stock Units

The following table summarizes the restricted stock, performance unit, and phantom stock unit activity in the Stock-based Compensation Plans for the years ended December 31, 2012, 2011, and 2010.

	Restricted Stock			Performance Units			Phantom Stock Units		
	Number of Shares	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)	Number of Units	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)	Number of Units[1]	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)
Unvested at January 1, 2010	2,028,683	$39.44		—	$—		475,063	$27.91	
Awarded	1,006,163	24.69		264,500	31.63		153,135	25.96	
Vested	(645,660)	40.66	$19,806	—	—	$—	(65,140)	41.88	$1,910
Forfeited	(116,865)	36.55		—	—		(52,449)	35.28	
Unvested at December 31, 2010	2,272,321	32.71		264,500	31.63		510,609	24.79	
Awarded	1,025,782	27.30		226,000	27.53		500	28.24	
Vested	(610,681)	61.33	18,416	—	—	—	(52,587)	60.04	1,449
Forfeited	(131,330)	23.51		(41,000)	29.98		(25,737)	19.12	
Spin-off adjustment[2]	—			233,740			225,004		
Vested due to spin-off[3]	—			(19,000)	20.81	—	(342,765)	15.15	3,246
Unvested at September 30, 2011	2,556,092	24.18		664,240	19.52		315,024	12.15	
Awarded	25,700	15.19		—	—		941,300	15.08	
Vested	(48,560)	28.84	595	—	—	—	(3,505)	17.07	43
Forfeited	(59,120)	23.93		(9,120)	20.81		(14,002)	16.21	
Unvested at December 31, 2011	2,474,112	24.00		655,120	19.50		1,238,817	14.32	
Awarded	1,743,757	9.95		789,500	13.40		718,500	6.73	
Vested	(956,547)	19.51	7,667	(323,760)	18.18	—	(608,543)	14.15	4,511
Forfeited	(539,685)	18.65		(181,680)	17.55		(187,037)	13.10	
Unvested at December 31, 2012	2,721,637	$17.64		939,180	$15.20		1,161,737	$9.91	

(1) All of the unvested units of phantom stock at December 31, 2012 must be settled in cash. The phantom stock units have been accounted for as a liability within the Consolidated Financial Statements. Of the 608,543 phantom stock units that vested during 2012, 6,080 units were settled in shares of common stock and 602,463 units were settled in cash. Of the 398,857 phantom stock units that vested during 2011, 5,500 units were settled in shares of common stock and 393,357 units were settled in cash. Of the 65,140 phantom stock units that vested in 2010, 63,750 were settled in shares of common stock and 1,390 units were settled in cash.

(2)

In conjunction with the spin-off of Lone Pine, the number of performance units and phantom stock units outstanding was adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans. In addition, the initial stock prices used to measure Forest's total shareholder returns over the performance periods of the performance units were adjusted in accordance with the antidilution provisions provided for by the Stock-based Compensation Plans. The number of restricted stock awards outstanding was not adjusted as a result of the spin-off since holders of restricted stock awards received Lone Pine common shares in the spin-off.

(3) In conjunction with the spin-off of Lone Pine, Lone Pine employees were deemed to have been involuntarily terminated under the terms of their phantom stock agreements, and, therefore, all phantom stock units held by Lone Pine employees vested on September 30, 2011 and were settled in cash by Lone Pine. The single Lone Pine employee who held a performance unit award was deemed to have been involuntarily terminated under the terms of his performance unit agreement at the time of the spin-off and, therefore, his performance units vested on September 30, 2011, but with no shares deliverable under his agreement. No Forest restricted stock awards were held by Lone Pine employees at the time of the spin-off.

The grant date fair value of the restricted stock was determined by averaging the high and low stock price of a share of common stock as published by the New York Stock Exchange on the date of grant. The restricted stock generally vests on the third anniversary of the date of the award, but may vest earlier upon a qualifying disability, death, retirement, certain involuntary terminations, or a change in control of the Company in accordance with the term of the underlying agreement.

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The grant date fair value of the phantom stock units was determined by averaging the high and low stock price of a share of common stock as published by the New York Stock Exchange on the date of grant. Phantom stock units outstanding prior to the fourth quarter of 2011 generally vest on the third anniversary of the date of the award. In the fourth quarter of 2011, the Company granted 941,300 phantom stock units to employees, which vest in one-third increments on each of the first three anniversaries of the date of grant. In the fourth quarter of 2012, the Company granted 718,500 phantom stock units to certain Company officers. The awards vest over a four-year period in accordance with the following schedule: (i) 10% on the first anniversary of the grant date; (ii) 20% on the second anniversary of the grant date; (iii) 30% on the third anniversary of the grant date; and (iv) 40% on the fourth anniversary of the grant date. Like restricted stock, phantom stock units may vest earlier due to certain circumstances, as discussed above.

Beginning in 2010, Forest has made annual grants of performance units to its officers. Under the terms of the award agreements, each performance unit represents a contractual right to receive one share of Forest’s common stock; provided that the actual number of shares that may be deliverable under an award will range from 0% to 200% of the number of performance units awarded, depending on Forest’s relative total shareholder return in comparison to an identified peer group over a thirty-six month performance period. The grant date fair values of these awards were determined using a process that takes into account probability-weighted shareholder returns assuming a large number of possible stock price paths, which are modeled based on inputs such as volatility and the risk-free interest rate.

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the “ESPP”), under which it is authorized to issue up to .8 million shares of common stock. Employees who are regularly scheduled to work more than 20 hours per week and more than five months in any calendar year may participate in the ESPP. Currently, under the terms of the ESPP, employees may elect each calendar quarter to have up to 15% of their annual base earnings withheld to purchase shares of common stock, up to a limit of $25,000 of common stock per calendar year. The purchase price of a share of common stock purchased under the ESPP is equal to 85% of the lower of the beginning-of-quarter or end-of-quarter market price. ESPP participants are restricted from selling the shares of common stock purchased under the ESPP for a period of six months after purchase. As of December 31, 2012, the Company had .1 million shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2012, 2011, and 2010 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of purchase rights granted during the periods presented:

	Year Ended December 31,		
	2012	2011	2010
Expected option life	3 months	3 months	3 months
Risk free interest rates	.02% - .10%	.02% - .15%	.08% - .17%
Estimated volatility	46%	59%	38%
Dividend yield	0%	0%	0%
Weighted average fair market value of purchase rights granted	$2.43	$5.00	$7.78

(7) EMPLOYEE BENEFITS:

Pension Plans and Postretirement Benefits

The Company has a qualified defined benefit pension plan that covers certain employees and former employees in the United States (the “Forest Pension Plan”). The Company also has a non-qualified unfunded supplementary retirement plan (the “SERP”) that provides certain retired executives with defined retirement benefits in excess of qualified plan limits imposed by federal tax law. The Forest Pension Plan and the SERP were curtailed

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and all benefit accruals under both plans were suspended effective May 31, 1991. In addition, as a result of The Wiser Oil Company acquisition in 2004, Forest assumed a noncontributory defined benefit pension plan (the “Wiser Pension Plan,” and together with the “Forest Pension Plan,” the “Pension Plans”). The Wiser Pension Plan was curtailed and all benefit accruals were suspended effective December 11, 1998. The Forest Pension Plan, the Wiser Pension Plan, and the SERP are hereinafter collectively referred to as the “Plans.”

In addition to the Plans described above, Forest also provides postretirement benefits to certain employees in the U.S. hired on or prior to January 1, 2009, their beneficiaries, and covered dependents. These benefits, which consist primarily of medical benefits payable on behalf of retirees in the U.S., are referred to as the “Postretirement Benefits Plan” throughout this Note.

Expected Benefit Payments

As of December 31, 2012, it is anticipated that the Company will be required to provide benefit payments from the Forest Pension Plan trust and the Wiser Pension Plan trust and fund benefit payments directly for the SERP and the Postretirement Benefits Plan in 2013 through 2017 and in the aggregate for the years 2018 through 2022 in the following amounts:

	2013	2014	2015	2016	2017	2018-2022
	(In Thousands)					
Forest Pension Plan(1)	$2,399	$2,318	$2,267	$2,196	$2,145	$9,770
Wiser Pension Plan(1)	852	840	829	820	809	3,845
SERP	130	127	123	119	114	496
Postretirement Benefits Plan	710	704	684	659	675	3,607

(1) Benefit payments expected to be made to participants in the Forest Pension Plan and Wiser Pension Plan are expected to be paid out of funds held in trusts established for each plan.

Forest anticipates that it will make contributions in 2013 totaling $1.6 million to the Plans and $.6 million to the Postretirement Benefits Plan, net of retiree contributions, as applicable.

Benefit Obligations

The following table sets forth the estimated benefit obligations associated with the Company’s Pension Plans and Postretirement Benefits Plan.

	Year Ended December 31,			
	Pension Plans		Postretirement Benefits Plan	
	2012	2011	2012	2011
	(In Thousands)			
Benefit obligation at the beginning of the year	$44,755	$42,213	$13,498	$9,212
Service cost	—	—	1,131	825
Interest cost	1,554	1,836	547	529
Actuarial loss	2,902	3,931	2,613	3,645
Benefits paid	(3,194)	(3,225)	(619)	(779)
Retiree contributions	—	—	57	66
Benefit obligation at the end of the year	$46,017	$44,755	$17,227	$13,498

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Fair Value of Plan Assets

The Company's Pension Plans' assets measured at fair value on a recurring basis are set forth by level within the fair value hierarchy in the table below as of the dates indicated (see Note 8 for information on the fair value hierarchy). There were no changes to the valuation techniques used during the period. There are no assets set aside under the SERP and the Postretirement Benefits Plan. During 2012, the amount of contributions in the case of the Postretirement Benefit Plan, equals the amount of benefits paid.

	December 31, 2012				December 31, 2011			
	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total
	(In Thousands)							
Investment funds—equities:								
Research equity portfolio[1]	$—	$10,379	$—	$10,379	$—	$9,681	$—	$9,681
International stock funds[2]	10,479	—	—	10,479	10,363	—	—	10,363
Investment funds—fixed income:								
Short-term fund[3]	1,994	—	—	1,994	1,549	—	—	1,549
Bond fund[4]	4,801	—	—	4,801	4,166	—	—	4,166
Oil and gas royalty interests[5]	—	—	138	138	—	—	198	198
	$17,274	$10,379	$138	$27,791	$16,078	$9,681	$198	$25,957

(1) This investment fund's assets are primarily large capitalization U.S. equities. The investment approach of this fund, which typically holds 110 - 130 securities, focuses on diversifying the investment portfolio by delegating the equity selection process to research analysts with expertise in their respective industries. Industry weights are kept similar to those of the S&P 500 Index. As of December 31, 2012, the sector weighting of this fund was comprised of the following: information technology (18%), financials (16%), consumer discretionary (14%), health care (13%), energy (11%), consumer staples (11%), and other (17%). The fair value of this investment fund was determined based on the net asset value per unit provided by the investee. Forest performs procedures to validate the net asset value per unit provided by the investee. Such procedures include verifying a sample of the net asset values of the underlying securities, which are directly observable in the marketplace.

(2) These three investment funds seek long-term growth of principal and income by investing primarily in diversified portfolios of equity securities issued by foreign, medium-to-large companies in international markets including emerging markets. The first fund typically holds 50 - 100 securities and seeks to invest in solid, well-established global leaders with emphasis on strong corporate governance, positive future growth opportunities, and growing return on capital. As of December 31, 2012, the sector weighting of this fund, which seeks diversification across

regions, countries, and market sectors, was comprised of the following: financials (25%), health care (16%), consumer discretionary (13%), information technology (12%), and other (34%). The second fund seeks to obtain growth through long-term appreciation of its holdings, selecting investments based upon their current fundamentals. As of December 31, 2012, the sector weighting of this fund, which invests in Asian (excluding Japanese) growth equities with a focus on domestic demand growth rather than an export orientation, was comprised of the following: financials (32%), information technology (15%), consumer staples (14%), consumer discretionary (12%), and other (27%). The third fund seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets equity securities. As of December 31, 2012, the sector weighting of this fund, which holds approximately 80 positions across the portfolio, with country allocations not exceeding 25%, was comprised of the following: information technology (19%), financials (18%), energy (17%), materials (15%), and other (31%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are directly observable in the marketplace.

(3) This investment fund's assets are high-quality money market instruments and short-term fixed income securities. This fund is actively managed as an enhanced cash strategy, seeking to derive excess returns versus money market fund indices by capturing term, transactional liquidity, credit, and volatility premiums. As of December 31, 2012, the sector weighting of this fund was comprised of the following: government related (33%), investment grade (29%), mortgage (13%), and other (25%). The fair value of this investment fund was determined based on the fund's net asset value per unit, which is directly observable in the marketplace.

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(4) These two investment funds consist of diversified portfolios of bonds. The first fund's main investments are intermediate maturity fixed income securities with a duration between three and six years, with a maximum of 10% of the portfolio being invested in securities below Baa grade, and up to 30% of the portfolio being invested in non-U.S. dollar denominated securities. As of December 31, 2012, the sector weighting of this fund was comprised of the following: mortgage (40%), government-related (25%), non-U.S. dollar developed market (11%), investment grade (10%), and other (14%). The second fund seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets debt securities. As of December 31, 2012, the sector weighting of this fund, which holds approximately 80 positions across the portfolio, with country allocations not exceeding 25%, was comprised of the following: sovereign-local (41%), inflation linked (30%), corporates (22%), and sovereign U.S. dollar denominated (7%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are directly observable in the marketplace.

(5) The oil and gas royalty interests are valued at their estimated discounted future cash flows, which approximate fair value.

The following table sets forth a rollforward of the fair value of the plan assets.

	Year Ended December 31,			
	Pension Plans		Postretirement Benefits Plan	
	2012	2011	2012	2011
	(In Thousands)			
Fair value of plan assets at beginning of the year	$25,957	$29,609	$—	$—
Actual return on plan assets	4,048	(1,566)	—	—
Retiree contributions	—	—	57	66
Employer contribution	980	1,139	562	713
Benefits paid	(3,194)	(3,225)	(619)	(779)
Fair value of plan assets at the end of the year	$27,791	$25,957	$—	$—

The following table presents a reconciliation of the beginning and ending balances of the Company's Pension Plan assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Year Ended December 31,	
	2012	2011
	Oil and Gas Royalty Interests	
	(In Thousands)	
Balance at beginning of period	$198	$161
Actual return on plan assets	119	66
Purchases, sales, and settlements (net)	(179)	(29)
Transfers in and/or out of Level 3	—	—
Balance at end of period	$138	$198

Investments of the Plans

The Pension Plans' assets are invested with a view toward the long term in order to fulfill the obligations promised to participants as well as to control future funding levels. The Company continually reviews the levels of funding and investment strategy for the Pension Plans. Generally, the strategy includes allocating the Pension Plans' assets between equity securities and fixed income securities, depending on economic conditions and funding needs, although the strategy does not define any specified minimum exposure for any point in time. The equity and fixed income asset allocation levels in place from time to time are intended to achieve an appropriate balance between capital appreciation, preservation of capital, and current income.

The overall investment goal for the Pension Plans' assets is to achieve an investment return that allows the assets to achieve the assumed actuarial interest rate and to exceed the rate of inflation. In order to manage risk, in terms of volatility, the portfolios are designed with the intent of avoiding a loss of 20% during any single year and

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expressing no more volatility than experienced by the S&P 500 Index. The Pension Plans' investment allocation target is up to 75% equity, with discretion to vary the mix temporarily, in response to market conditions.

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan are set forth in the following table as of the dates indicated:

	December 31,			
	Forest Pension Plan		Wiser Pension Plan	
	2012	2011	2012	2011
Fixed income securities	24 %	22 %	25 %	21 %
Equity securities	75 %	76 %	74 %	78 %
Other	1 %	2 %	1 %	1 %
	100 %	100 %	100 %	100 %

Funded Status

The following table sets forth the funded status of the Company's Pension Plans and Postretirement Benefits Plan.

	December 31,			
	Pension Plans		Postretirement Benefits Plan	
	2012	2011	2012	2011
	(In Thousands)			
Excess of benefit obligation over plan assets	$(18,225)	$(18,798)	$(17,227)	$(13,498)
Unrecognized actuarial loss	24,811	25,192	5,633	3,214
Net amount recognized	$6,586	$6,394	$(11,594)	$(10,284)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—noncurrent	$(18,225)	$(18,798)	$(17,227)	$(13,498)
Accumulated other comprehensive income—net actuarial loss	24,811	25,192	5,633	3,214
Net amount recognized	$6,586	$6,394	$(11,594)	$(10,284)

The following table sets forth the projected and accumulated benefit obligations for the Pension Plans compared to the fair value of the plan assets for the periods indicated.

	December 31,	
	2012	2011
	(In Thousands)	
Projected benefit obligation	$46,017	$44,755
Accumulated benefit obligation	46,017	44,755
Fair value of plan assets	27,791	25,957

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Annual Periodic Expense and Actuarial Assumptions

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions.

	Year Ended December 31,					
	Pension Plans			Postretirement Benefits Plan		
	2012	2011	2010	2012	2011	2010
	(Dollar Amounts In Thousands)					
Service cost	$—	$—	$—	$1,131	$825	$668
Interest cost	1,554	1,836	2,005	547	529	430
Expected return on plan assets	(1,744)	(2,014)	(1,952)	—	—	—
Recognized actuarial loss (gain)	979	651	606	194	—	(40)
Total net periodic expense	$789	$473	$659	$1,872	$1,354	$1,058
Assumptions used to determine net periodic expense:						
Discount rate	3.58%	4.50%	5.04%	4.14%	5.15%	5.55%
Expected return on plan assets	7%	7%	7%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	2.98%	3.58%	4.50%	3.68%	4.14%	5.15%

The discount rates used to determine benefit obligations were determined by adjusting composite AA bond yields to reflect the difference between the duration of the future estimated cash flows of the Plans and the Postretirement Benefits Plan obligations and the duration of the composite AA bond yields. The expected rate of return on plan assets was determined based on historical returns.

The Company estimates that net periodic expense for the year ended December 31, 2013 for the Pension Plans and for the Postretirement Benefits Plan will include expense of $.9 million and $.2 million, respectively, resulting from the amortization of the related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2012.

The assumed health care cost trend rate for the next year and thereafter that was used to measure the expected cost of benefits covered by the Postretirement Benefits Plan was 5.5%. Assumed health care cost trend rates can have a significant effect on the amounts reported for the Postretirement Benefits Plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Year Ended December 31, 2012	
	Postretirement Benefits Plan	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$471	$(344)
Effect on postretirement benefit obligation	3,839	(2,914)

Other Employee Benefit Plans

Forest sponsors various defined contribution plans under which the Company contributed matching contributions equal to $3.7 million in 2012, $3.7 million in 2011, and $3.3 million in 2010.

Forest also provides life insurance benefits for certain retirees and former executives under split dollar life insurance plans. Under the life insurance plans, the Company is assigned a portion of the benefits. No current employees are covered by these plans. The Company has recognized a liability for the estimated cost of maintaining the insurance policies during the postretirement periods of the retirees and former executives, with such liability

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accreted each period to its present value. The Company's estimate of costs expected to be paid in 2013 to maintain these life insurance policies is $1.0 million. Forest recognized accretion expense related to the split dollar life insurance obligations of $.9 million, $1.0 million, and $1.0 million for the years ended December 31, 2012, 2011, and 2010, respectively. The discount rates used to determine the accretion expense were 3.19%, 4.08%, and 4.01% for the years ended December 31, 2012, 2011, and 2010, respectively. The split dollar life insurance obligation recognized in the Consolidated Balance Sheets was $7.3 million as of December 31, 2012 and 2011. The discount rates used to determine the obligations were 2.57% and 3.19% as of December 31, 2012 and 2011, respectively. The cash surrender value of the split dollar life insurance policies recognized in the Consolidated Balance Sheets was $3.6 million as of December 31, 2012 and 2011.

(8) FAIR VALUE MEASUREMENTS:

The Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2012 and 2011 are set forth by level within the fair value hierarchy in the table below.

Description	December 31, 2012	2011
	Using Significant Other Observable Inputs (Level 2)[1] (In Thousands)	
Assets:		
Derivative instruments:[2]		
Commodity	$35,465	$79,487
Interest rate	13,060	20,556
Total Assets	$48,525	$100,043
Liabilities:		
Derivative instruments:[2]		
Commodity	$16,551	$28,944
Interest rate	—	—
Total Liabilities	$16,551	$28,944

(1) The authoritative accounting guidance regarding fair value measurements for assets and liabilities measured at fair value establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers consist of: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when relevant observable inputs are not available. The Company uses the income approach to value its derivative instruments under the Level 2 hierarchy. There were no transfers between levels of the fair value hierarchy during 2012. The Company's policy is to recognize transfers between levels of the fair value hierarchy as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

(2) The Company's derivative assets and liabilities include commodity and interest rate derivatives (see Note 9 for more information on these instruments). The Company utilizes present value techniques and option-pricing models for valuing its derivatives. Inputs to these valuation techniques include published forward prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. All of the significant inputs are observable, either directly or indirectly; therefore, the Company's derivative instruments are included within the Level 2 fair value hierarchy.

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The fair values and carrying amounts of the Company's financial instruments are summarized below as of the dates indicated.

	December 31, 2012			
			Fair Value Measurements:	
	Carrying Amount	Total Fair Value[1]	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)
	(In Thousands)			
Assets:				
Derivative instruments	$48,525	$48,525	$—	$48,525
Liabilities:				
Derivative instruments	16,551	16,551	—	16,551
Credit facility	65,000	65,000	—	65,000
8½% senior notes due 2014	296,723	321,000	321,000	—
7¼% senior notes due 2019	1,000,365	1,006,850	1,006,850	—
7½% senior notes due 2020	500,000	526,250	526,250	—

(1) The Company used various assumptions and methods in estimating the fair values of its financial instruments. The fair values of the senior notes were estimated based on quoted market prices. The carrying amount of the credit facility approximated fair value due to the short original maturities of the borrowings and because the borrowings bear interest at variable market rates. The methods used to determine the fair values of the derivative instruments are discussed above. See also Note 9 for more information on the derivative instruments.

	December 31, 2011	
	Carrying Amount	Fair Value[1]
	(In Thousands)	
Assets:		
Derivative instruments	$100,043	$100,043
Liabilities:		
Derivative instruments	28,944	28,944
Credit facility	105,000	105,000
8½% senior notes due 2014	587,611	653,250
7¼% senior notes due 2019	1,000,421	1,025,000

(1) The Company used various assumptions and methods in estimating the fair values of its financial instruments. The fair values of the senior notes were estimated based on quoted market prices. The carrying amount of the credit facility approximated fair value due to the short original maturities of the borrowings and because the borrowings bear interest at variable market rates. The methods used to determine the fair values of the derivative instruments are discussed above. See also Note 9 for more information on the derivative instruments.

(9) DERIVATIVE INSTRUMENTS:

Commodity Derivatives

Forest periodically enters into commodity derivative instruments such as swap and collar agreements as an attempt to moderate the effects of wide fluctuations in commodity prices on Forest's cash flow and to manage the exposure to commodity price risk. Forest's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, Forest has elected not to designate its derivatives as hedging

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instruments for accounting purposes. As such, Forest recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the Consolidated Statement of Operations.

The table below sets forth Forest's outstanding commodity swaps as of December 31, 2012.

Commodity Swaps

Swap Term	Natural Gas (NYMEX HH) Bbtu Per Day	Natural Gas (NYMEX HH) Weighted Average Hedged Price per MMBtu	Oil (NYMEX WTI) Barrels Per Day	Oil (NYMEX WTI) Weighted Average Hedged Price per Bbl
Calendar 2013	160	$3.98	4,000	$95.53
Calendar 2014	40	4.50	—	—

In connection with several natural gas and oil swaps entered into, Forest granted swaptions to the swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas and oil swaps. These swaptions grant the swap counterparties the option to enter into future swaps with Forest and may not be exercised until their expiration dates. The table below sets forth the outstanding swaptions as of December 31, 2012.

Commodity Options

Underlying Term	Option Expiration	Natural Gas (NYMEX HH) Underlying Bbtu Per Day	Natural Gas (NYMEX HH) Underlying Hedged Price per MMBtu	Oil (NYMEX WTI) Underlying Barrels Per Day	Oil (NYMEX WTI) Underlying Hedged Price per Bbl
Gas Swaptions:					
Calendar 2014	December 2013	30	$4.50	—	$—
Calendar 2014	December 2013	10	4.51	—	—
Oil Swaptions:					
Calendar 2014	December 2013	—	—	2,000	110.00
Calendar 2014	December 2013	—	—	1,000	109.00
Calendar 2014	December 2013	—	—	2,000	100.00
Calendar 2015	December 2014	—	—	3,000	100.00

Derivative Instruments Entered Into Subsequent to December 31, 2012

Subsequent to December 31, 2012, through February 21, 2013, Forest entered into the following derivative instruments:

Commodity Swaps

Swap Term	Natural Gas (NYMEX HH) Bbtu Per Day	Natural Gas (NYMEX HH) Weighted Average Hedged Price per MMBtu
Calendar 2014(1)	40	$4.19

(1) In connection with entering into these natural gas swaps with premium hedged prices, Forest amended the terms of existing oil swaptions with the counterparties for Calendar 2014 covering 2,000 barrels per day, changing the hedged price per barrel from $110.00 to $100.00.

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Interest Rate Derivatives

Forest has entered into interest rate derivative instruments in an attempt to manage the mix of fixed and floating interest rates within its debt portfolio. The Company has elected not to designate its derivatives as hedging instruments for accounting purposes. As such, the Company recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the Consolidated Statement of Operations. The table below sets forth Forest's outstanding fixed-to-floating interest rate swaps as of December 31, 2012.

Interest Rate Swaps

Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate
January 2013 - February 2014	$500,000	1 month LIBOR + 5.89%	8.50 %

Fair Value and Gains and Losses

The table below summarizes the location and fair value amounts of Forest's derivative instruments reported in the Consolidated Balance Sheets as of the dates indicated. These derivative instruments are not designated as hedging instruments for accounting purposes. For financial reporting purposes, Forest does not offset asset and liability fair value amounts recognized for derivative instruments with the same counterparty under its master netting arrangements. See Note 8 for more information on the determination of the fair values of Forest's derivative instruments.

	December 31,	
	2012	2011
	(In Thousands)	
Current assets:		
Derivative instruments:		
Commodity	$28,690	$79,487
Interest rate	11,500	10,134
Total current assets	$40,190	$89,621
Long-term assets:		
Derivative instruments:		
Commodity	$6,775	$—
Interest rate	1,560	10,422
Total long-term assets	$8,335	$10,422
Current liabilities:		
Derivative instruments:		
Commodity	$9,347	$28,944
Long-term liabilities:		
Derivative instruments:		
Commodity	$7,204	$—

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The table below summarizes the amount of derivative instrument gains and losses reported in the Consolidated Statements of Operations as realized and unrealized (gains) losses on derivative instruments, net, for the periods indicated. These derivative instruments are not designated as hedging instruments for accounting purposes.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Commodity derivatives:			
Realized gains	$(100,420)	$(37,535)	$(99,762)
Unrealized losses (gains)	31,630	(37,542)	(18,390)
Interest rate derivatives:			
Realized gains	(11,352)	(11,442)	(12,450)
Unrealized losses (gains)	7,496	(1,545)	(19,530)
Realized and unrealized gains on derivative instruments, net	$(72,646)	$(88,064)	$(150,132)

Due to the volatility of oil, natural gas, and NGL prices, the estimated fair values of Forest's commodity derivative instruments are subject to large fluctuations from period to period. Forest has experienced the effects of these commodity price fluctuations in both the current period and prior periods and expects that volatility in commodity prices will continue.

Credit Risk

Forest executes with each of its derivative counterparties an International Swap and Derivatives Association, Inc. ("ISDA") Master Agreement, which is a standard industry form contract containing general terms and conditions applicable to many types of derivative transactions. Additionally, Forest executes, with each of its derivative counterparties, a Schedule, which modifies the terms and conditions of the ISDA Master Agreement according to the parties' requirements and the specific types of derivatives to be traded. As of December 31, 2012, all but one of Forest's derivative counterparties are lenders, or affiliates of lenders, under the Credit Facility. The terms of the Credit Facility provide that any security granted by Forest thereunder shall also extend to and be available to those lenders that are counterparties to derivative transactions. None of these counterparties requires collateral beyond that already pledged under the Credit Facility. The remaining counterparty, a purchaser of Forest's natural gas production, generally owes money to Forest and therefore does not require collateral under the ISDA Master Agreement and Schedule it has executed with Forest.

The ISDA Master Agreements and Schedules contain cross-default provisions whereby a default under the Credit Facility will also cause a default under the derivative agreements. Such events of default include non-payment, breach of warranty, non-performance of the financial covenant, default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the Credit Facility. In addition, bankruptcy and insolvency events with respect to Forest or certain of its U.S. subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. None of these events of default is specifically credit-related, but some could arise if there were a general deterioration of Forest's credit. The ISDA Master Agreements and Schedules contain a further credit-related termination event that would occur if Forest were to merge with another entity and the creditworthiness of the resulting entity was materially weaker than that of Forest.

The majority of Forest's derivative counterparties are financial institutions that are engaged in similar activities and have similar economic characteristics that, in general, could cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions. Forest does not require the posting of collateral for its benefit under its derivative agreements. However, the ISDA Master Agreements and Schedules generally contain netting provisions whereby if on any date amounts would otherwise be payable by each party to the other, then on such date, the party that owes the larger amount will pay the excess of that amount over the smaller amount owed by the other party, thus satisfying each party's obligations. These provisions generally apply to

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all derivative transactions, or all derivative transactions of the same type (e.g. commodity, interest rate, etc.), with the particular counterparty. If all counterparties failed, Forest would be exposed to a risk of loss equal to this net amount owed to Forest, the fair value of which was $33.3 million at December 31, 2012. If Forest suffered an event of default, each counterparty could demand immediate payment, subject to notification periods, of the net obligations due to it under the derivative agreements. At December 31, 2012, Forest owed a net derivative liability to one counterparty, the fair value of which was $1.3 million. In the absence of netting provisions, at December 31, 2012, Forest would be exposed to a risk of loss of $48.5 million under its derivative agreements and Forest’s derivative counterparties would be exposed to a risk of loss of $16.6 million.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was enacted. As part of a broader financial regulatory reform, the Dodd-Frank Act includes derivatives reform that may impact Forest’s business. Congress delegated many of the details of the Dodd-Frank Act to federal regulatory agencies. Forest is monitoring the impact, if any, that the Dodd-Frank Act and related rules will have on its existing derivative transactions under its outstanding ISDA Master Agreements and Schedules, as well as its ability to enter into such transactions and agreements in the future.

(10) COMMITMENTS AND CONTINGENCIES:

The table below shows the Company’s future payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2012.

	2013	2014	2015	2016	2017	After 2017	Total
	(In Thousands)						
Operating leases(1)	$30,070	$24,188	$17,573	$17,026	$10,032	$10,135	$109,024
Unconditional purchase obligations(2)	1,935	140	105	—	—	—	2,180
	$32,005	$24,328	$17,678	$17,026	$10,032	$10,135	$111,204

(1) Includes future rental payments for office facilities and equipment, drilling rigs, and compressors under the remaining terms of non-cancelable operating leases with initial terms in excess of one year.

(2) Includes unconditional purchase obligations for throughput and voice and data services. Payments made under these unconditional purchase obligations were $.8 million in each of the years 2012, 2011, and 2010.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties approximated $15.6 million in 2012, $21.0 million in 2011, and $14.0 million in 2010. Net rental payments under non-cancelable operating leases, including compressor rentals, charged to expense approximated $22.0 million in 2012, $16.5 million in 2011, and $18.4 million in 2010. The Company has no leases that are accounted for as capital leases.

Forest, in the ordinary course of business, is a party to various lawsuits, claims, and proceedings. While the Company believes that the amount of any potential loss upon resolution of these matters would not be material to its consolidated financial position, the ultimate outcome of these matters is inherently difficult to predict with any certainty. In the event of an unfavorable outcome, the potential loss could have an adverse effect on Forest’s results of operations and cash flow. Forest is also involved in a number of governmental proceedings in the ordinary course of business, including environmental matters.

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(11) COSTS, EXPENSES, AND OTHER:

The table below sets forth the components of “Other, net” in the Consolidated Statements of Operations for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Accretion of asset retirement obligations	$6,663	$6,082	$6,158
Legal proceeding liabilities	29,251	6,500	—
Loss (gain) on debt extinguishment, net	36,312	—	(4,576)
Other, net	11,180	4,582	5,757
	$83,406	$17,164	$7,339

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations is the expense recognized to increase the carrying amount of the liability associated with Forest’s asset retirement obligations as a result of the passage of time. See Note 1 for more information on Forest’s asset retirement obligations.

Legal Proceeding Liabilities

On February 29, 2012, two members of a three-member arbitration panel reached a decision adverse to Forest in the proceeding styled, Forest Oil Corporation, et al. v. El Rucio Land & Cattle Company, Inc., et al., which occurred in Harris County, Texas. The third member of the arbitration panel dissented. The proceeding was initiated in January 2005 and involves claims asserted by the landowner-claimant based on the diminution in value of its land and related damages allegedly resulting from operational and reclamation practices employed by Forest in the 1970s, 1980s, and early 1990s. The arbitration decision awards the claimant $22.8 million in damages and attorneys’ fees and additional injunctive relief regarding future surface-use issues. On October 9, 2012, after vacating a portion of the decision imposing a future bonding requirement on Forest, the trial court for the 55th Judicial District, in the District Court in Harris County, Texas, reduced the arbitration decision to a judgment. Forest is seeking to have this judgment reversed on appeal and believes it has meritorious arguments in support thereof. However, Forest is unable to predict the final outcome in this matter and has accrued a liability, which is classified within “Other liabilities” in the Consolidated Balance Sheet, of $23.0 million, which includes accrued interest, for this matter.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities (“PERL”). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL “abandoned” its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field (“Trading Bay”). On December 2, 2010, Union Oil Company of California (“Unocal”) filed a lawsuit styled, Union Oil Company of California v. Forest Oil Corporation. In the lawsuit, the plaintiff complained about PERL’s abandonment of Trading Bay and asserted that PERL has failed to pay approximately $49.0 million in joint interest billings owed on those properties to date from the time PERL owned them. The plaintiff claimed that, as predecessor of PERL, Forest was liable for PERL’s share of all joint interest billings owed on Trading Bay. As of December 31, 2011, Unocal sold its interest in the Trading Bay assets, including its claims against Forest, to Hilcorp Alaska, LLC, and Hilcorp was substituted for Unocal as plaintiff in the lawsuit. In August 2012, Forest and the plaintiff reached a settlement whereby the plaintiff released Forest from all claims, agreed to indemnify Forest with respect to all decommissioning and abandonment liabilities associated with Trading Bay, and dismissed the complaint against Forest in exchange for a $7.0 million payment from Forest.

On March 7, 2011, Pacific Energy Resources Ltd., Pacific Energy Alaska Holdings LLC, and Pacific Energy Alaska Operating LLC filed suit against Forest Oil Corporation and Forest Alaska Holdings LLC in United States Bankruptcy Court in the District of Delaware. In this suit, the plaintiffs claimed that, at the time Forest sold

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Pacific Energy Resources Ltd. its Alaska assets, those assets were overvalued due to Forest's alleged nondisclosure, fraud, and negligent misrepresentations and that, as a result, the sales transaction rendered Pacific Energy Resources Ltd. insolvent. The plaintiffs sought to recover over $250.0 million in value from Forest. During 2011, Forest and the plaintiffs in this action reached a settlement whereby the plaintiffs released Forest from all claims and agreed to dismiss the complaint against Forest in exchange for a $6.5 million payment from Forest.

Loss (Gain) on Debt Extinguishment

In October 2012, Forest redeemed $300.0 million of the 8½% Notes at 110.24% of par, recognizing a loss of $36.3 million upon redemption due to the $30.7 million call premium and write-off of $5.6 million of unamortized discount and debt issue costs.

The net gain on debt extinguishment for the year ended December 31, 2010 includes the net gain related to the January 2010 redemption of $150.0 million 7¾% senior notes due 2014 at 101.292% of par. A net gain was recognized upon redemption due to the write-off of $7.6 million of unamortized deferred gains resulting from the previous termination of interest rate swaps related to these notes. This gain was partially offset by the $1.9 million call premium and write-off of $1.1 million of unamortized discount and debt issue costs.

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(12) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2012				
Oil, natural gas, and natural gas liquids sales	$158,901	$135,694	$156,014	$154,914
Costs and expenses associated directly with products sold(1)	$110,110	$110,996	$114,304	$104,048
Earnings (loss) before income taxes(2)	$(31,758)	$(344,099)	$(451,272)	$(288,365)
Net earnings (loss)(2)	$(32,673)	$(511,173)	$(458,552)	$(286,533)
Basic earnings (loss) per share	$(.29)	$(4.44)	$(3.97)	$(2.48)
Diluted earnings (loss) per share	$(.29)	$(4.44)	$(3.97)	$(2.48)
2011				
Oil, natural gas, and natural gas liquids sales				
As reported(3)	$202,571	$237,848	$174,012	$176,616
Less: discontinued operations	36,261	51,255	—	—
Oil, natural gas, and natural gas liquids sales from continuing operations	$166,310	$186,593	$174,012	$176,616
Costs and expenses associated directly with products sold(1):				
As reported(3)	$118,465	$126,479	$89,343	$105,377
Less: discontinued operations	31,325	34,873	—	—
Costs and expenses associated directly with products sold from continuing operations	$87,140	$91,606	$89,343	$105,377
Earnings (loss) before income taxes(2):				
As reported(3)	$(5,047)	$90,682	$94,166	$31,662
Less: discontinued operations	9,247	14,821	—	—
Earnings (loss) from continuing operations before income taxes	$(14,294)	$75,861	$94,166	$31,662
Net earnings (loss)(2)	$(3,330)	$38,974	$87,718	$19,467
Net earnings (loss) attributable to Forest Oil Corporation common shareholders(2)(4)	$(3,330)	$38,910	$82,795	$19,467
Basic earnings (loss) per share attributable to Forest Oil Corporation common shareholders	$(.03)	$.34	$.72	$.17
Diluted earnings (loss) per share attributable to Forest Oil Corporation common shareholders	$(.03)	$.34	$.72	$.17

(1) Costs and expenses associated directly with products sold is comprised of lease operating expenses, production and property taxes, transportation and processing costs, depletion expense, and accretion of asset retirement obligations.

(2) Earnings (loss) before income taxes, net earnings (loss), and net earnings (loss) attributable to Forest Oil Corporation common shareholders have been impacted by non-cash ceiling test write-downs in every quarter of 2012 as discussed in Note 1 and are also subject to large fluctuations due to Forest's election not to use cash flow hedge accounting for derivative instruments as discussed in Note 9.

(3) Amounts shown for the first and second quarters of 2011 are those amounts that were previously reported in Forest's Quarterly Reports on Form 10-Q prior to the September 30, 2011 spin-off of Lone Pine, whose results are now reported as discontinued operations.

(4) Upon completion of Lone Pine's initial public offering on June 1, 2011, Forest maintained a controlling interest in Lone Pine until it was spun-off on September 30, 2011. As such, during the second and third quarters of 2011, Forest had net earnings attributable to the noncontrolling interest.

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(13) DISCONTINUED OPERATIONS:

Lone Pine was a component of Forest with operations and cash flows clearly distinguishable, both operationally and for financial reporting purposes, from those of Forest. As a result of the spin-off of Lone Pine on September 30, 2011, Lone Pine's operations and cash flows were eliminated from the ongoing operations of Forest, and Forest will not have any significant continuing involvement in the operations of Lone Pine. Accordingly, Forest has presented Lone Pine's results of operations as discontinued operations in the Consolidated Statements of Operations for the periods presented. For more information regarding the spin-off see Note 5.

The table below presents the major components of earnings from discontinued operations for the periods presented.

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
	(In Thousands)	
Total revenues	$137,834	$146,070
Production expenses	40,350	38,841
General and administrative	8,846	8,318
Depreciation, depletion, and amortization	60,780	63,645
Interest expense	3,866	381
Realized and unrealized gains on derivative instruments, net	(33,628)	—
Realized foreign currency exchange gains	(33,869)	(270)
Unrealized foreign currency exchange losses (gains), net	28,488	(14,290)
Other, net	1,328	729
Earnings from discontinued operations before tax	61,673	48,716
Income tax	17,104	10,857
Net earnings from discontinued operations	$44,569	$37,859

(14) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

The Company's 8½% senior notes due 2014, 7¼% senior notes due 2019, and 7½% senior notes due 2020 have been fully and unconditionally guaranteed by a 100%-owned subsidiary of the Company (the "Guarantor Subsidiary"). The Company's remaining subsidiaries (the "Non-Guarantor Subsidiaries") have not provided guarantees. The Guarantor Subsidiary's guarantee may be released automatically under the following customary circumstances:

- in connection with any sale or other disposition of all or substantially all of the property of the Guarantor Subsidiary (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) a restricted subsidiary of the Company;

- in connection with any sale or other disposition of the capital stock of the Guarantor Subsidiary to a person that is not (either before or after giving effect to such transaction) a restricted subsidiary of the Company;

- if the Company designates that Guarantor Subsidiary as an unrestricted subsidiary in accordance with the applicable provisions of the indentures;

- if the Company exercises its legal defeasance option or its covenant defeasance option or upon satisfaction and discharge of the indentures; or

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- at such time as such Guarantor Subsidiary ceases to guarantee any other indebtedness of the Company, provided that at such time it does not have outstanding an aggregate of $25.0 million or more of indebtedness and preferred stock.

The following presents condensed consolidating financial information as of December 31, 2012 and 2011, and for the three years in the period ended December 31, 2012 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiaries, eliminating entries, and consolidated basis. Eliminating entries presented are necessary to combine the entities.

CONDENSED CONSOLIDATING BALANCE SHEETS
(In Thousands)

	December 31, 2012				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$667	$45	$344	$—	$1,056
Accounts receivable	33,979	27,969	6,393	(825)	67,516
Other current assets	55,869	286	353	—	56,508
Total current assets	90,515	28,300	7,090	(825)	125,080
Property and equipment, at cost	8,439,898	1,416,364	182,070	—	10,038,332
Less accumulated depreciation, depletion, and amortization	6,937,606	1,173,332	173,156	—	8,284,094
Net property and equipment	1,502,292	243,032	8,914	—	1,754,238
Investment in subsidiaries	68,048	—	—	(68,048)	—
Goodwill	216,460	22,960	—	—	239,420
Due from subsidiaries	116,602	83,983	—	(200,585)	—
Deferred income taxes	111,015	—	36,106	(132,440)	14,681
Other assets	68,443	—	—	—	68,443
	$2,173,375	$378,275	$52,110	$(401,898)	$2,201,862
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable and accrued liabilities	$157,404	$2,133	$6,074	$(825)	$164,786
Other current liabilities	55,187	67	6,285	—	61,539
Total current liabilities	212,591	2,200	12,359	(825)	226,325
Long-term debt	1,862,088	—	—	—	1,862,088
Due to parent and subsidiaries	—	—	200,585	(200,585)	—
Deferred income taxes	—	132,440	—	(132,440)	—
Other liabilities	141,520	3,642	11,111	—	156,273
Total liabilities	2,216,199	138,282	224,055	(333,850)	2,244,686
Shareholders’ equity (deficit)	(42,824)	239,993	(171,945)	(68,048)	(42,824)
	$2,173,375	$378,275	$52,110	$(401,898)	$2,201,862

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CONDENSED CONSOLIDATING BALANCE SHEETS (Continued)
(In Thousands)

	December 31, 2011				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$1,734	$1	$1,277	$—	$3,012
Accounts receivable	43,999	34,142	2,201	(1,253)	79,089
Other current assets	127,667	313	591		