FOREST OIL CORP
Form 10-K
February 26, 2014

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, 2013
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 o No x
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. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, was $483,491,861 (based on the closing price of such stock).

There were 119,076,708 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 19, 2014.

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, 2013 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 (sometimes referred to as "NGLs") 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, 2013 were approximately 625 Bcfe, all of which are located in the United States.

Strategy

Forest's long-term operating strategy seeks to build shareholder value by pursuing the development of oil and natural gas assets within our operational areas located in Eagle Ford in South Texas; Ark-La-Tex in East Texas, Louisiana, and Arkansas; and Permian Basin in West Texas. We strive to maintain a large number of commodity-diverse drilling locations that provide us with the flexibility to allocate capital to projects that generate the highest margins depending on the current commodity price environment, which currently include oil or natural gas liquids drilling projects. We devoted the majority of our capital expenditures to oil and natural gas liquids projects in 2013 and we plan to continue to do so in 2014. Our asset base and development efforts are focused in areas where we have concentrated land positions, a large drilling inventory, and operational control. Our growth strategy may also be supplemented from time to time through opportunistic acquisitions that complement our existing asset base to increase the size and scale of our development and resource opportunities. We may also sell properties when the opportunity arises or business conditions warrant, as demonstrated by the sale of our natural gas assets in South Texas and our Texas Panhandle properties in 2013.

Core Operational Areas

Our core operational areas consist of drilling projects that have exposure to oil, natural gas, and natural gas liquids. Our primary areas of focus in 2014 will be in Eagle Ford in South Texas and Ark-La-Tex in East Texas.

Eagle Ford

Our Eagle Ford assets are located in Gonzales County in South Texas. During 2013, we continued progress toward holding an aggregate of 49,000 gross (24,500 net) acres in the area and we currently anticipate that this will be accomplished during the first half of 2014. In April 2013, we announced a joint development agreement with an industry partner that allowed us to increase our pace of drilling activity during 2013 and implement technological refinements and enhancements. These enhancements involve ongoing micro-seismic and subsurface data analysis and reservoir studies that are being used to optimize well placement, lateral length, and fracture stimulation techniques and design. We are attempting to operate more efficiently through a combination of decreased drilling and completion time, the utilization of a more targeted completion design, and capitalizing on operational synergies associated with pad drilling. Drilling and completion costs for 2013 averaged $6 million per gross well as compared to $7 million for

the wells drilled in 2012. In addition, we have entered into a gathering, treating, and processing agreement that will provide central facility gathering, transportation, gas processing, and water handling for our Eagle Ford production. This will help streamline our operations and provide cost savings for this oil asset. The facility is expected to be fully operational by the fourth quarter of 2014. We expect to see improvement in well costs

following the completion of centralized production facilities, the use of existing pad locations, and continued optimization of completion techniques. In 2014, we plan to operate a two-rig drilling program in Eagle Ford.

Ark-La-Tex

We currently hold an acreage position of 234,000 gross (162,000 net) acres in the greater Ark-La-Tex. Approximately 78% of the acreage is held by production, of which 85% is operated by Forest. We believe that this asset base provides repeatable and predictable drilling and recompletion opportunities within multiple stacked-pay intervals, including the Cotton Valley, Haynesville, and other formations. Recent drilling activity has focused on the liquids-rich Cotton Valley and other formations in East Texas. During 2012, we changed our focus to target primarily liquids-rich drilling projects to take advantage of these higher-margin opportunities as a result of a decrease in natural gas prices. In 2013, we continued to primarily target the Cotton Valley formation and experienced relatively consistent and predictable results. We drilled a total of six wells in 2013 that had a 30-day average gross production rate of 8.7 MMcfe/d (40% liquids). In 2014, we plan to continue targeting the Cotton Valley and our efforts will focus on transitioning to multi-well pad drilling in certain areas to improve efficiency as we seek to reduce well costs. We plan to operate a three-rig drilling program in Ark-La-Tex during 2014.

Acquisition and Divestiture Activities

We currently have no plans for acquisitions. However, in the future we may pursue acquisitions that meet our criteria for investment returns. We also may divest non-core assets from time to time to, among other things, upgrade our portfolio, increase our operational efficiencies, and improve our financial position. As described below, we have focused on divestitures in recent years in order to reduce our indebtedness.

In October 2013, we entered into an agreement to sell all of our oil and natural gas properties located in the Texas Panhandle for $1 billion in cash. The purchase price was adjusted at closing on November 25, 2013 to $944 million in order to, among other things, reflect an economic effective date of October 1, 2013. In addition to the net cash proceeds of $944 million received at closing, $44 million was closed into escrow, which Forest may receive as consents-to-assign are received and post-closing title curative work is completed. Moreover, there is an additional $10 million in escrow that supports post-closing indemnities that we may owe to the buyer under the terms of the purchase and sale agreement. Any of the $10 million remaining in escrow at the one-year anniversary of the closing will be paid to us. As of February 19, 2014, we have received $21 million of the $44 million closed into escrow. We estimated the proved reserves associated with these properties were 517 Bcfe at the time of sale.

In August 2013, we entered into an agreement to sell a portion of our largely undeveloped acreage position located in Crockett County in the Permian Basin of West Texas. This transaction closed on September 10, 2013 and we received net cash proceeds of $31 million.

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 oil properties. This transaction closed on February 15, 2013 and we received net cash proceeds of $321 million. We estimated the proved reserves associated with these properties were 223 Bcfe at the time of sale.

In November 2012, we sold all of our oil and natural gas properties located in South Louisiana for net cash proceeds of $211 million. We estimated the proved reserves associated with these properties were 39 Bcfe at the time of sale. In October 2012, we sold the majority of our East Texas natural gas gathering assets for net cash proceeds of $29 million.

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. We estimated the proved reserves associated with these properties were 510 Bcfe at the time of spin-off.

In 2009, we sold oil and natural gas properties located in the Permian Basin in West Texas and New Mexico in three separate transactions for net proceeds of $908 million in cash. We estimated the proved reserves associated with these properties were 541 Bcfe at the time of sale.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2013, all of which are located in the United States, based on the NYMEX Henry Hub ("HH") price of $3.67 per MMBtu for natural gas and the NYMEX West Texas Intermediate ("WTI") price of $97.33 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, 2013. See "Preparation of Reserves Estimates" below and Note 14 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	336,342	6,151	6,855	414,378
Undeveloped	118,249	10,523	4,856	210,523
Total estimated proved reserves	454,591	16,674	11,711	624,901

(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 2013, the average of the first-day-of-the-month natural gas price was $3.67 per Mcf, and the average of the first-day-of-the-month oil price was $97.33 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 27 Mcf per barrel of oil and approximately 10 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2013).

As of December 31, 2013, we had estimated proved reserves of 625 Bcfe, a decrease of 54% compared to 1,363 Bcfe of estimated proved reserves at December 31, 2012. During 2013, we added 148 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2013 drilling activity in the Eagle Ford in South Texas and Cotton Valley in East Texas. These reserve additions were offset by property sales of 800 Bcfe and net negative revisions of 10 Bcfe. The net negative revisions of 10 Bcfe were comprised of (i) the reclassification of 41 Bcfe of proved undeveloped reserves ("PUDs") to probable undeveloped reserves for PUDs that are not expected to be developed five years from the time the reserves were initially disclosed, (ii) negative performance revisions of 9 Bcfe, and (iii) positive pricing revisions of 40 Bcfe.

As of December 31, 2013, we had estimated proved undeveloped reserves of 211 Bcfe, or 34% of estimated proved reserves, compared to 425 Bcfe, or 31% of estimated proved reserves as of December 31, 2012. The net decrease of 215 Bcfe was primarily due to property sales including 286 Bcfe of proved undeveloped reserves. During 2013, we invested $75 million to convert 22 Bcfe of our December 31, 2012 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 the last several years, 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. This trend continued throughout 2013, however, we expect to increase our PUD conversion rate in 2014. As of December 31, 2013, 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 36 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.

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. 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, 2013, 2012, and 2011, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2013, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 87% of our reserves by NPV as of December 31, 2013. 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 quantities for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily

responsible for overseeing the audit of our reserves received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University, 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 39 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

The following table summarizes the number of wells drilled during 2013, 2012, and 2011, 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, 2013, we had 9 gross (5 net) wells in progress, all of which are located in the United States. During 2013, we drilled a total of 93 gross (45 net) wells, of which 41 were classified as exploratory and 52 were classified as development.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive[1]	52	23	106	49	101	44
Non-productive[2]	—	—	3	1	—	—
Total development wells	52	23	109	50	101	44
Exploratory wells:						
Productive[1]	40	21	27	24	22	21
Non-productive[2]	1	1	3	3	4	3
Total exploratory wells	41	22	30	27	26	24

(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, 2013, 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, 2013, we owned interests in 40 gross wells containing multiple completions.

	Gross	Net
Natural Gas	1,432	1,001
Oil	93	68
Total	1,525	1,069

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, 2013. 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, 2013, approximately 36%, 30%, and 16% of our net undeveloped acreage in the United States was held under leases that will expire in 2014, 2015, and 2016, respectively, if not extended by exploration or production activities.

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States[1]	239,089	159,927	189,999	121,008
South Africa[2]	—	—	1,235,500	657,286
Italy	—	—	107,043	86,507
Total	239,089	159,927	1,532,542	864,801

(1) Concentrations of net acres in the United States as of December 31, 2013 include: 162,000 net acres in Ark-La-Tex in East Texas, Louisiana, and Arkansas; 24,500 net acres in Eagle Ford; and 63,500 net acres in Permian Basin in West Texas.

(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 abandonment of the Block 2C Exploration Right was completed in December 2013, with Forest receiving $9 million. The disposal of our interest in the Block 2A Production Right is contingent upon the approval of the government of South Africa, which has not yet occurred. Upon the completion of this transaction, if it occurs, 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, 2013, 2012, and 2011 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,		
	2013	2012	2011
Liquids:			
Oil and condensate:			
Production volumes (MBbls)	2,271	3,146	2,491
Average sales price (per Bbl)	$96.30	$96.14	$96.22
Natural gas liquids:			
Production volumes (MBbls)	2,521	3,489	3,154
Average sales price (per Bbl)	$29.79	$31.77	$42.91
Total liquids:			
Production volumes (MBbls)	4,792	6,635	5,645
Average sales price (per Bbl)	$61.31	$62.29	$66.43
Natural Gas:			
Production volumes (MMcf)	46,676	81,008	88,497
Average sales price (per Mcf)	$3.16	$2.37	$3.71
Total production volumes (MMcfe)[(1)]	75,428	120,818	122,367
Average sales price (per Mcfe)	$5.85	$5.01	$5.75
Production costs (per Mcfe):			
Lease operating expenses	$1.02	$.89	$.81
Transportation and processing costs	.16	.12	.11
Production costs excluding production and property taxes (per Mcfe)	1.17	1.02	.92
Production and property taxes	.20	.28	.33
Total production costs (per Mcfe)	$1.37	$1.30	$1.25

(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 2013, the average of the first-day-of-the-month natural gas price was $3.67 per Mcf, and the average of the first-day-of-the-month oil price was $97.33 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 27 Mcf per barrel of oil and approximately 10 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2013).

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 19, 2014.

Competition

We encounter intense competition in all aspects of our business, including acquisition of properties and oil and natural gas leases, marketing oil and natural gas, obtaining services, and securing drilling rigs and other

equipment necessary for drilling and completing wells. In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Our ability to increase production and 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 greater and more productive assets, substantially larger staffs, and greater financial and operational resources than we have. Many of our competitors not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also may have integrated operations that include refining and processing of oil and natural gas products as well as the distribution and marketing of such products. Because of our relatively small size and capital constraints, we may find it increasingly difficult to 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. As a result, our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and, consequently, could affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Matters subject to current governmental regulation or pending legislative or regulatory changes include the production, handling, storage, transportation, and disposal of oil and natural gas, by-products from oil and natural gas, and other substances produced or used in connection with oil and natural gas operations. Jurisdictions in which we operate have adopted laws and regulations governing 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 natural gas production. In order to conserve supplies of oil and natural gas, these agencies may restrict the rates of flow of oil and natural 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. 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 natural 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 requirements and oversight on our derivatives transactions, including 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. 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.

Additional proposals and proceedings that might affect the oil and natural gas industry are regularly considered by Congress, the states, local governments, 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 natural 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 natural gas. Although we believe 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 or strict liability without regard to fault or the legality of the original conduct and 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 or injunctive 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 natural 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, control requirements, requirements for disclosure of chemical constituents, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds and in some municipalities. 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 asserted potential 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 all 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" and "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" 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. The scope of the EPA's authority to regulate GHG emissions, however, is currently being reviewed by the U.S. Supreme Court, with a decision expected in spring or summer of 2014. 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) are to report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. These rules have increased compliance costs on our operations.

We believe 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. In addition, some pollution-related risks may not be insurable.

Employees

As of December 31, 2013, we had 363 employees. As of February 19, 2014, we had 223 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 reserves, proved developed 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.

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. Also referred to as a non-productive 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.

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. 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.

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.

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 the Audit, Compensation, and Nominating and Corporate Governance committees of our Board of Directors, 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, beliefs, expectations, estimates, projections, forecasts, and assumptions about future events and are based on currently available information. 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;
- operational initiatives and their effect on our production, expenses, and 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

difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and natural 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 73% of our estimated proved reserves at December 31, 2013 were natural gas, causing us to be particularly dependent on prices for natural gas. Low commodity prices may mean that it will not be economical to drill or produce oil and 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 decline in commodity prices may have numerous effects on our business, including the following:

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

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

•prohibiting us from developing our current properties, or from growing our asset base; or

•making it more difficult to pay interest and principal on our indebtedness and satisfy our other obligations.

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, 2013 and February 19, 2014, we had a principal amount of long-term indebtedness of $800 million.

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 increases 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, including the mix and quality of our assets and our ability to develop and produce them. Many of these factors are beyond our control.

Over the past few years we have sold a significant amount of developed and undeveloped assets, and used the proceeds to reduce outstanding indebtedness. Despite these efforts, our debt remains relatively high in comparison to our remaining operating cash flows and assets. Our cash flows from our remaining assets may not be 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. As a result, we may be required, if possible, to refinance or restructure the debt, sell additional assets, or sell shares of our common or preferred equity securities — all on terms that we do not find attractive. We also may be required to reduce expenses by curtailing operations.

The governing documents of our debt instruments contain covenants and restrictions that require us to 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. In addition, if not waived by the relevant lenders, a default could lead to foreclosure of our assets, which in turn could result in bankruptcy.

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 $400 million in connection with the closing of the sale of our assets in the Texas Panhandle on November 25, 2013. The next scheduled redetermination of the borrowing base will occur on or before May 1, 2014, at which time our borrowing base may be further reduced. 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, or further downward reductions of our reserves, likely will result in a redetermination 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.

Volatility in the public and private capital markets may make 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 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 to EBITDA (as adjusted for non-cash charges) calculated for the preceding four consecutive fiscal quarter period then most recently ended to be greater than a specified amount. In September 2013, we amended the facility to increase the permitted ratio to 5.0 to 1.0 for any time after September 11, 2013 up to and including March 31, 2014, and to 4.75 to 1.0 for any time after April 1, 2014 up to and including June 30, 2014. After June 30, 2014, the ratio returns to the original restriction of 4.5 to 1.0. Our ratio of total debt to EBITDA for the four consecutive fiscal quarter period ending December 31, 2013, as calculated in accordance with our bank credit facility, was 4.3. 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. Based on our current projections, absent an amendment to the bank credit facility, we expect the ratio of total debt to EBITDA to exceed the maximum allowed sometime during the second or third quarter of 2014. Non-compliance with the terms of our debt covenants or other credit provisions could result in all amounts outstanding under our bank credit facility and, potentially, our indentures, becoming due and payable immediately, and the resultant termination of our bank credit facility. This would result, at a minimum, in the need to slow or cease the incurrence of capital and operational expenditures, which would have a negative impact on our expected

production, revenues and, potentially, on our reserves. At worse, it could also result in foreclosure of our assets and potential bankruptcy. See Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” for a more complete discussion of our debt obligations and liquidity.

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

Compared to many of our competitors in the oil and gas industry, we are a very small company. We face difficulties in competing with 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. We face intense competition in all areas of our business from companies with greater and more productive assets, substantially larger staffs, and greater financial and operating resources than we have. In addition, legacy costs associated with our relatively long period of existence may result in our operating costs being greater than competitors of similar size. Our limited size has placed us at a disadvantage with respect to funding our operating costs, and 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.

We also compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business. For instance, since the beginning of 2013 alone, three executive officers resigned their positions with Forest, and Forest's employee resignation rate was 16% per annum versus the historic norm of 10%. Continued difficulty in retaining quality personnel may have a negative impact on our operations.

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, 2013, approximately 34% 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, 2013 were based on a NYMEX HH price of $3.67 per MMBtu for natural gas and a NYMEX WTI price of $97.33 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, 2013, and an average realization for a barrel of natural gas liquids during that period equal to approximately 31% of the NYMEX WTI price or $29.93. For the year ended December 31, 2012, the comparable prices used to calculate our estimated proved reserves were $2.76 per MMBtu for natural gas, $94.79 per barrel for oil, and an average realization for a barrel of natural gas liquids equal to approximately 36% of the oil price or $33.83. Despite the increase in prices from those used to estimate proved reserves as of December 31, 2012, which resulted in positive reserve revisions of 40 Bcfe during 2013, we revised our estimated proved reserves downward during 2013 by 41 Bcfe due to the reclassification of proved undeveloped reserves ("PUDs") to probable undeveloped reserves for PUDs that are not

expected to be developed five years from the time the reserves were initially disclosed and by 9 Bcfe due to negative performance revisions. We may be required to make further downward revisions in our proved reserves in the future. 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, 2013 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 also 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, 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, 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 is 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 2013 we incurred a ceiling test write-down of $58 million. 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, 2013, 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.

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Much 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 43% 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. 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. We cannot be sure that we will be able to maintain all of our leased properties by initiating production. Any such loss of properties could reduce our access to capital and have a negative impact on our operations.

The marketability of our production is dependent upon gathering, 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. These issues can result in wells being shut in or in us receiving lower prices for our production. 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 operations and cash flow. We are subject to similar risks with respect to processing facilities and other midstream infrastructure and services.

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

Drilling activities 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, as would be the case had we elected to use hedge accounting. As a consequence, we may report material changes in fair value, or unrealized losses or gains, on our hedging agreements prior to their expiry. The amount of the actual cash settlements, or 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, among other things, imposes requirements and oversight on hedging

transactions, including clearing and margin requirements under certain circumstances. 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. Most notably, the EPA is conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. A draft report is expected sometime in 2014. 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.

Federal, state, and local regulatory developments could adversely impact our operations in a variety of ways, including by causing us to incur increased capital expenditures and costs. For example, 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. The EPA currently is reconsidering parts of these air rules, with expected finalization in November 2014. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

In addition, federal agencies have recently announced at least 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 ("DOI") 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. The DOI has not yet finalized these rules. 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 EPA has not yet finalized this

guidance. 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.

Item 1B. Unresolved Staff Comments.

As of December 31, 2013, 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 Corp., et al. v. El Rucio Land & Cattle Co., 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 was subsequently amended to drop the allegation regarding the forest fires.) 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. 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.

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 19, 2014, our Common Stock was held by 587 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. There were no cash dividends declared on the Common Stock in 2012 or 2013. On February 19, 2014, the closing price of Forest Common Stock was $3.22.

		Common Stock	
		High	Low
2012	First Quarter	$15.15	$11.61
	Second Quarter	13.69	6.22
	Third Quarter	9.32	5.68
	Fourth Quarter	9.12	6.06
2013	First Quarter	$7.44	$5.18
	Second Quarter	5.43	3.77
	Third Quarter	6.67	4.02
	Fourth Quarter	6.52	3.43

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 governing Forest's 7¼% senior notes due 2019 and 7½% senior notes due 2020 and (iv) Forest's bank credit facility dated as of June 30, 2011, as amended. 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 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 equity securities, our ability to pay

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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, 2013.

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2013. 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 2013	89,653	$5.35	—	—
November 2013	40,612	4.29	—	—
December 2013	3,116	3.76	—	—
Fourth Quarter Total	133,381	$4.99	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2008 (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.

Comparison Of 5 Year Cumulative Total Return*
Among Forest Oil Corporation, the S&P 500 Index,
and the Dow Jones US Exploration & Production Index

*$100 invested on 12/31/08 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.

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, 2013. 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 divestitures 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 divestitures.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and natural gas liquids sales[1]	$441,341	$605,523	$703,531	$707,692	$655,579
Net earnings (loss) from continuing operations	$73,924	$(1,288,931)	$98,260	$189,662	$(793,789)
Net earnings (loss) from discontinued operations[2]	—	—	44,569	37,859	(129,344)
Net earnings (loss)	73,924	(1,288,931)	142,829	227,521	(923,133)
Less: net earnings attributable to noncontrolling interest[2]	—	—	4,987	—	—
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$73,924	$(1,288,931)	$137,842	$227,521	$(923,133)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:					
Earnings (loss) from continuing operations	$.62	$(11.21)	$.86	$1.68	$(7.61)
Earnings (loss) from discontinued operations	—	—	.35	.33	(1.24)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.21	$2.01	$(8.85)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:					
Earnings (loss) from continuing operations	$.62	$(11.21)	$.85	$1.67	$(7.61)
Earnings (loss) from discontinued operations	—	—	.34	.33	(1.24)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.19	$2.00	$(8.85)
Total assets[1]	$1,117,952	$2,201,862	$3,381,151	$3,070,197	$3,169,054
Long-term debt[1]	$800,179	$1,862,100	$1,693,044	$1,869,372	$2,022,514
Shareholders’ equity (deficit)	$54,469	$(42,824)	$1,193,113	$1,352,787	$1,079,154

OPERATING DATA[1]					
Annual production:					
Oil (MBbls)	2,271	3,146	2,491	2,357	3,397
Natural gas (MMcf)	46,676	81,008	88,497	101,346	116,029
NGLs (MBbls)	2,521	3,489	3,154	3,589	3,012
Average sales price:					
Oil (per Bbl)	$96.30	$96.14	$96.22	$76.08	$56.87
Natural gas (per Mcf)	$3.16	$2.37	$3.71	$3.99	$3.33
NGLs (per Bbl)	$29.79	$31.77	$42.91	$34.54	$25.17

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

(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.

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, 2013 were approximately 625 Bcfe, all of which are located in our one reportable geographical segment - the United States. Our core operational areas are in Eagle Ford in South Texas and Ark-La-Tex in Texas, Louisiana, and Arkansas. See Item 1 "Business" for a discussion of our business strategy and core operational areas of focus.

2013 Highlights

Forest's 2013 highlights were as follows:

- Reduced the outstanding principal of our long-term debt by $1.1 billion.

- Received cash proceeds of $1.3 billion from the property divestiture program we initiated in 2012, including $321 million for the South Texas divestiture and $965 million for the Panhandle divestiture.

- Increased total oil and NGL sales volumes to 38% of total equivalent sales volumes compared to 33% in 2012 and 28% in 2011. Pro forma for property divestitures in 2012 and 2013, total oil and NGL sales volumes were 29% of total equivalent sales volumes in 2013 compared to 19% in 2012.

- Entered into an agreement with a third-party for the development of our Eagle Ford acreage in South Texas. Under the terms of the agreement, the third-party will pay a $90 million drilling carry in exchange for a 50% working interest in our Eagle Ford acreage position. We are the operator of the drilling program. As of December 31, 2013, we had realized $61 million of the drilling carry.

- Increased Eagle Ford average net sales volumes by 62% over 2012 to approximately 2,550 boe/d.

- Reduced drilling and completion costs per well in the Eagle Ford by 15% over 2012.

Results of Operations

Forest recorded net earnings in 2013 of $74 million as compared to a net loss of $1.3 billion in 2012. Net earnings in 2013 included a $193 million net gain recognized on the sale of our assets in the Texas Panhandle, a $49 million loss

on the early extinguishment of debt, $31 million in unrealized losses on derivative instruments, and a $58 million ceiling test write-down. The net loss in 2012 was primarily due to ceiling test write-downs and other non-cash property impairments totaling $1.1 billion as well as a $245 million valuation allowance placed against 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. The 2012 net loss also included $39 million in unrealized losses on derivative instruments and a $36 million loss on the early extinguishment of debt.

Adjusted EBIDTA, which is a performance measure not calculated in accordance with generally accepted accounting principles ("GAAP"), is commonly used by management, securities analysts, and investors and excludes non-cash items such as depletion expense, deferred income tax expense, and ceiling test write-downs. Our Adjusted EBITDA was $333 million in 2013 as compared to $514 million in 2012. The decrease of $181 million was primarily attributable to property divestitures during 2013, which reduced revenues and, to a lesser extent, reduced production expense. See "Reconciliation of Non-GAAP Measure" at the end of this Item 7 for a reconciliation of Adjusted EBITDA to net earnings (loss) from continuing operations, the most directly comparable financial measure calculated and presented in accordance with GAAP.

During 2013, we completed two large oil and natural gas property divestitures, as discussed in Part I, Item 1 "Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements. Because of these divestitures, we anticipate that our 2014 oil, natural gas, and natural gas liquids sales volumes, revenues, and production expense will be lower as compared to 2013. Additionally, we expect 2014 interest expense and general and administrative expense to be lower as compared to 2013 due to less debt and fewer employees, respectively.

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, 2013, 2012, and 2011, are set forth in the table below.

	Year Ended December 31,		
	2013	2012	2011
Sales volumes:			
Oil (MBbls)	2,271	3,146	2,491
Natural gas (MMcf)	46,676	81,008	88,497
NGLs (MBbls)	2,521	3,489	3,154
Totals (MMcfe)	75,428	120,818	122,367
Revenues (in thousands):			
Oil	$218,704	$302,445	$239,695
Natural gas	147,530	192,220	328,510
NGLs	75,107	110,858	135,326
Totals	$441,341	$605,523	$703,531
Average sales price per unit:			
Oil ($/Bbl)	$96.30	$96.14	$96.22
Natural gas ($/Mcf)	3.16	2.37	3.71
NGLs ($/Bbl)	29.79	31.77	42.91
Totals ($/Mcfe)	$5.85	$5.01	$5.75

Equivalent sales volumes were 75.4 Bcfe in 2013 as compared to 120.8 Bcfe in 2012. The 38% decrease in equivalent sales volumes in 2013 compared to 2012 was primarily due to divestitures of producing oil and natural gas properties in South Louisiana, South Texas, and the Texas Panhandle, which occurred in November 2012, February 2013, and November 2013, respectively. The decreases due to asset sales were partially offset by an increase in oil production primarily from our Eagle Ford operations in South Texas. Revenues from oil, natural gas, and NGLs were $441 million in 2013 as compared to $606 million in 2012. The $164 million decrease was primarily the result of the net decrease in equivalent sales volumes, which was partially offset by a 17% increase in the average sales price per Mcfe between the two periods from $5.01 per Mcfe in 2012 to $5.85 per Mcfe in 2013.

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Equivalent sales volumes from continuing operations decreased 1% in 2012 compared to 2011. 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.

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

Production Expense

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$76,675	$108,027	$99,158
Production and property taxes	14,857	34,249	40,632
Transportation and processing costs	11,895	14,633	13,728
Production expense	$103,427	$156,909	$153,518
Production expense per Mcfe:			
Lease operating expenses	$1.02	$.89	$.81
Production and property taxes	.20	.28	.33
Transportation and processing costs	.16	.12	.11
Production expense per Mcfe	$1.37	$1.30	$1.25

Lease Operating Expenses

Lease operating expenses in 2013 were $77 million, or $1.02 per Mcfe, compared to $108 million, or $.89 per Mcfe, in 2012. Lease operating expenses decreased $31 million in 2013 compared to 2012 due to the oil and natural gas property divestitures that occurred in November 2012, February 2013, and November 2013. The increase in per-unit lease operating expenses is primarily due to a higher percentage of oil production as a percentage of total equivalent 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 $108 million, or $.89 per Mcfe, in 2012 compared to $99 million, or $.81 per Mcfe, in 2011. The increase in total and per-unit lease operating expenses was primarily due to increases in water disposal costs and workovers as well as an increase in oil production.

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 3.4%, 5.7%, and 5.8% of oil, natural gas, and NGL sales for the years ended December 31, 2013, 2012, and 2011, respectively. The decreases in production and property taxes as a percentage of

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revenues in 2013 compared to prior years were due to the November 2012 sale of the South Louisiana properties, which had higher associated production tax rates.

Transportation and Processing Costs

Transportation and processing costs were $12 million, or $.16 per Mcfe, in 2013, $15 million, or $.12 per Mcfe, in 2012, and $14 million, or $.11 per Mcfe, in 2011. The decrease in total transportation and processing costs in 2013 as compared to 2012 is due to the oil and natural gas property divestitures. However, the per-unit amount increased in 2013 as compared to 2012 due primarily to increased trucking charges for our oil production.

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,		
	2013	2012	2011
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$18,592	$22,897	$35,706
Stock-based compensation costs capitalized	(7,808)	(7,378)	(14,886)
	10,784	15,519	20,820
Other general and administrative costs	70,227	74,149	75,792
Other general and administrative costs capitalized	(26,185)	(30,406)	(31,507)
	44,042	43,743	44,285
General and administrative expense	$54,826	$59,262	$65,105

General and administrative expense was $55 million in 2013 compared to $59 million and $65 million in 2012 and 2011, respectively. For the year ended December 31, 2013, other general and administrative costs include $14 million ($11 million net of capitalized amounts) in employee-related asset divestiture costs, and stock-based compensation costs include $5 million ($2 million net of capitalized amounts) in accelerated stock-based compensation costs. These costs are associated with the sale of our South Texas and Panhandle oil and natural gas properties during the first and fourth quarters of 2013, respectively. For the year ended December 31, 2012, stock-based compensation costs include $5 million ($4 million net of capitalized amounts) in accelerated stock-based compensation costs, and other general and administrative costs include $2 million ($2 million net of capitalized amounts) in severance costs, both of which are related to the termination of our former chief executive officer. For the year ended December 31, 2011, $12 million in stock-based compensation costs ($7 million net of capitalized amounts) were recognized 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. The percentage of general and administrative costs capitalized remained consistent between the three years presented, ranging between 38% 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,		
	2013	2012	2011
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$171,557	$280,458	$219,684
Depreciation, depletion, and amortization expense per Mcfe	$2.27	$2.32	$1.80

Depreciation, depletion, and amortization expense ("DD&A") decreased $.05 per Mcfe to $2.27 per Mcfe in 2013 compared to $2.32 per Mcfe in 2012. DD&A was $2.32 per Mcfe in 2012 compared to $1.80 per Mcfe in 2011. The decrease in DD&A from 2012 to 2013 was due primarily to oil and natural gas property divestitures, partially offset by oil reserve additions, which typically have higher per-unit development costs than natural gas reserves. The increase in DD&A from 2011 to 2012 was due primarily to the increase in oil reserve additions. In addition, in 2012, a significant portion of our proved undeveloped natural gas reserves, which have lower associated development costs than 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.

Ceiling Test Write-Down of Oil and Natural Gas Properties

At December 31, 2013, we recorded a ceiling test write-down of our United States cost center totaling $58 million, pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting. This ceiling test write-down was primarily a result of the Panhandle divestiture in the fourth quarter of 2013. Given the magnitude of the Panhandle oil and natural gas reserves as a percentage of our total reserves, the divestiture resulted in a $193 million net gain on disposition of assets rather than 100% of the divestiture proceeds reducing capitalized costs, as has typically been done with previous sales of oil and natural gas properties. This smaller reduction of capitalized costs and the loss of future net revenues from the divested proved oil and natural gas reserves were the primary factors causing the ceiling test write-down. 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, 2013, unproved properties 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. See "Critical Accounting Policies, Estimates, Judgments and Assumptions—Full Cost Method of Accounting" for more information regarding ceiling test write-downs.

In 2012, we recorded ceiling test write-downs of our United States cost center totaling $958 million and our Italian cost center totaling $35 million. The United States 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. The Italian write-down resulted from our conclusion that our Italian natural gas reserves could no longer be classified as proved reserves, due to an Italian regional regulatory body's 2012 denial of 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.

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 had 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 to abandon a certain exploration right in South Africa in connection with the sale of the exploration right. The abandonment of the exploration right, which was contingent upon approval by the government of South Africa, among other things, was completed in December 2013, and we received $9 million, which is included in the Consolidated Statement of Operations within the "Other, net" line item for the year ended December 31, 2013. We are currently awaiting approval of the other sale by the government of 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 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,		
	2013	2012	2011
	(In Thousands)		
Interest costs	$121,796	$149,054	$160,014
Interest costs capitalized	(1,967)	(7,223)	(10,259)
Interest expense	$119,829	$141,831	$149,755

Interest expense in 2013 totaled $120 million compared to $142 million in 2012. The $22 million decrease in interest expense was primarily attributable to the redemption of $300 million of 8½% senior notes in October 2012, the redemption of the remaining $300 million of 8½% senior notes in March 2013, and the redemption of $700 million in aggregate of 7¼% senior notes and 7½% senior notes in November 2013. In addition, average outstanding borrowings under our credit facility also decreased during 2013. These decreases were partially offset by a full year of interest costs on the 7½% senior notes, which were issued in September 2012, and lower capitalized interest in 2013. Interest expense totaled $142 million in 2012 compared to $150 million in 2011. The 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 costs incurred on borrowings under our credit facility in 2012, interest costs on the $500 million of 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.

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. Realized gains and losses represent cash settlements on derivative instruments and unrealized gains and losses represent changes in the fair value of derivative instruments. See Note 8 and Note 9 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Realized losses (gains) on derivative instruments, net:			
Oil	$4,333	$(5,862)	$12,584
Natural gas	(18,585)	(91,891)	(78,247)
NGLs	—	(2,667)	28,128
Interest	(12,885)	(11,352)	(11,442)
Subtotal realized gains on derivative instruments, net	(27,137)	(111,772)	(48,977)
Unrealized (gains) losses on derivative instruments, net:			
Oil	(6,814)	(6,324)	(10,297)
Natural gas	24,677	43,350	(22,931)
NGLs	—	(5,396)	(4,314)
Interest	13,060	7,496	(1,545)
Subtotal unrealized losses (gains) on derivative instruments, net	30,923	39,126	(39,087)
Realized and unrealized losses (gains) on derivatives, net	$3,786	$(72,646)	$(88,064)

Other, Net

The table below sets forth the components of "Other, net" from continuing operations for the periods indicated.

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Gain on asset dispositions, net	$(202,023)	$—	$—
Loss on debt extinguishment, net	48,725	36,312	—
Legal proceeding liabilities	—	29,251	6,500
Accretion of asset retirement obligations	2,982	6,663	6,082
Other, net	7,710	11,180	4,582
	$(142,606)	$83,406	$17,164

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,		
	2013	2012	2011
	(In Thousands, Except Percentages)		
Current income tax	$(707)	$(35,538)	$30,141
Deferred income tax	—	208,975	58,994
Total income tax (benefit) expense	$(707)	$173,437	$89,135
Effective income tax rate	(1)%	(16)%	48%

Our effective income tax rates were (1)%, (16)%, and 48% for the years ended December 31, 2013, 2012, and 2011, respectively. The significant differences between our blended federal and state statutory income tax rate of 36% and our effective income tax rate for all the periods shown were primarily due to changes in the valuation allowance placed against our deferred tax assets. In addition, in 2011, our effective income tax rate was impacted by a 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.

The current income tax benefit 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.

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.

Discontinued Operations

The results of operations of Lone Pine are presented as discontinued operations in our Consolidated Financial Statements for 2011 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 62% of our total production in 2013 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 19, 2014, we had hedged, via commodity swaps and collars, approximately 33 Bcfe of our total projected 2014 production and approximately 9 Bcf of our total projected 2015 production, excluding outstanding commodity swaptions and oil put options. 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 19, 2014, 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 $400 million as of December 31, 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 and matures in June 2016. See "Bank Credit Facility" below for further details. We had no borrowings outstanding under our credit facility as of December 31, 2013 and February 19, 2014. As noted below under "Bank Credit Facility," our credit facility contains a covenant that we will not permit our ratio of total debt to EBITDA (as adjusted for non-cash charges) calculated for the preceding four consecutive fiscal quarter period then most recently ended to be greater than specified levels. 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 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. 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 more attractive capital projects and to enhance our financial flexibility. For example, in November 2012, we sold all of our oil and natural gas properties located in South Louisiana for net proceeds of $211 million. Additionally, in February 2013 we sold all of our oil and natural gas properties located in South Texas, excluding our Eagle Ford oil properties, for net proceeds of $321 million, which we used in March 2013 to redeem the remaining $300 million in principal amount of 8½% senior notes due 2014. In November 2013, we sold all of our oil and natural gas properties located in the Texas Panhandle for net proceeds to-date of $965 million, which we used in November 2013 to redeem $700 million aggregate principal amount of 7¼% senior notes due 2019 and 7½% senior notes due 2020, and to pay off the outstanding balance on our credit facility. In addition, we have entered into an agreement with a third-party pursuant to which the third-party is funding a portion of the drilling and other development costs relating to certain Eagle Ford acreage in exchange for a 50% working interest in that acreage.

We believe that our existing cash, expected cash flows provided by operating activities, and the funds available under our credit facility or alternative sources of debt financing will be sufficient to fund our normal recurring operating needs and our contractual obligations. As noted below under "Bank Credit Facility," we have initiated discussions with the administrative agent of our credit facility to obtain an amendment to temporarily increase the maximum ratio of total debt to EBITDA allowed under the credit facility. If we are unable to obtain an amendment, the Credit Facility could be terminated. However, we believe we can arrange for alternative sources of debt financing, including securing liens against our properties or selling additional properties, sufficient to meet our recurring operating needs and contractual obligations for a reasonable period of time. Additionally, if necessary, we have the ability to slow or cease the occurrence of certain capital and operational expenditures, including those related to initiating new drilling

programs, to preserve our available cash until these other sources of funding

become available at prudent terms. Any such reduction in expenditures would have a negative impact on our expected revenues, production and, potentially our reserves.

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. On September 12, 2013, we entered into the First Amendment to the Credit Facility (the "First Amendment"), which was effective as of that date. The First Amendment amended, among other things, the permitted ratio of total debt to EBITDA and the definition of total debt used in the ratio calculation, and reduced the borrowing base, which governs our availability under the Credit Facility, to $700 million.

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 natural gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and natural gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. A reduction of the borrowing base could require us to repay indebtedness in excess of the borrowing base in order to cover the deficiency. The next scheduled semi-annual redetermination of the borrowing base will occur on or about May 1, 2014. 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. The borrowing base is also subject to automatic adjustment if we or any of our Restricted Subsidiaries sell oil and natural gas properties having a fair market value, including any economic loss of unwinding any related hedging agreement, 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 Texas properties resulted in a $170 million reduction to the borrowing base when the transaction closed in February 2013 and the sale of our Panhandle properties resulted in a $300 million reduction to the borrowing base when the transaction closed in November 2013. See Note 2 to the Consolidated Financial Statements for more information regarding these divestitures. As of December 31, 2013, the borrowing base under the Credit Facility was $400 million.

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 our estimated proved oil and natural gas properties and related assets. If our corporate credit ratings issued by Moody's and Standard & Poor's 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 First Amendment to the Credit Facility provides that we will not permit the ratio of total debt to EBITDA (as adjusted for non-cash charges) calculated for the preceding four consecutive fiscal quarter period then most recently ended (i) for any time on or before September 11, 2013, to be greater than 4.50 to 1.00, (ii) for any time after September 11, 2013 and on or before March 31, 2014 to be greater than 5.00 to 1.00, (iii) for any time after April 1, 2014 and on or before June 30, 2014 to be greater than 4.75 to 1.00, and (iv) for any time after June 30, 2014, to be greater than 4.50 to 1.00. The First Amendment also amends the definition of total debt such that, during any period of four fiscal quarters that includes the calendar quarter in which the Panhandle divestiture closed, any cash proceeds from the Panhandle divestiture that are reported on our consolidated balance sheet on such date are subtracted from total debt. Depending on our overall level of indebtedness, this covenant may limit our ability to borrow funds as needed under the Credit Facility. Our ratio of total debt to EBITDA for the four consecutive fiscal quarter period ended December 31, 2013, as calculated in accordance with the Credit Facility, was 4.3. Based on our current projections, we expect the ratio of total debt to EBITDA to exceed the maximum allowed sometime during the second or third quarter of 2014 if we do not obtain an additional amendment to the Credit Facility. We have initiated discussions to that effect with the administrative agent of the Credit Facility and, with no amounts currently drawn against the facility, believe that we will be able to obtain such an amendment prior to the ratio exceeding the maximum amount currently allowed. If we fail to obtain an amendment, the Credit Facility could be terminated. However, we believe we can obtain alternative sources of debt financing sufficient for our needs, including securing liens against our properties or selling additional properties. Additionally, if necessary, we have the ability to slow or cease the occurrence of certain capital and operational expenditures, including those related to initiating new drilling programs, to preserve our available cash until these other sources of funding become available at prudent terms.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated with the resultant termination of the facility. 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. In addition, certain events of default under the Credit Facility will result in acceleration of the indebtedness under the Credit Facility, and termination of the 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, 2013 and February 19, 2014, there were no outstanding borrowings 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 $398 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 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 provided (used) by investing activities of continuing operations, and net cash (used) provided by financing activities of continuing operations for the years ended December 31, 2013, 2012, and 2011 were as follows:

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Net cash provided by operating activities of continuing operations	$201,759	$371,655	$398,097
Net cash provided (used) by investing activities of continuing operations	981,628	(467,782)	(759,730)
Net cash (used) provided by financing activities of continuing operations	(1,118,251)	94,171	(173,305)

Net cash provided by operating activities is primarily affected by sales volumes and commodity prices net of the effects of cash settlements of our derivative contracts and changes in working capital. The decrease in net cash provided by operating activities of $170 million in 2013 as compared to 2012 was primarily due to a $164 million decrease in revenue and a decrease in cash settlements on commodity derivatives of $86 million, partially offset by a $53 million decrease in production expense and a $13 million decrease in investment 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 cash settlements on commodity derivatives of $63 million.

The components of net cash provided (used) by investing activities of continuing operations for the years ended December 31, 2013, 2012, and 2011 were as follows:

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Exploration, development, and leasehold acquisition costs[(1)]	$(363,971)	$(721,536)	$(873,877)
Proceeds from sales of assets	1,347,116	262,882	121,115
Other fixed asset costs	(1,517)	(9,128)	(6,968)
Net cash provided (used) by investing activities of continuing operations	$981,628	$(467,782)	$(759,730)

(1) Cash paid for exploration, development, and leasehold acquisition 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 provided (used) by investing activities is primarily comprised of expenditures for the exploration and development of oil and natural gas properties net of proceeds from the dispositions of oil and natural gas properties and other capital assets. The $1.4 billion increase in cash provided by investing activities between 2013 and 2012 was primarily due to proceeds received from the divestiture of oil and natural gas properties, consisting principally of the

South Texas divestiture in February 2013 for $321 million, the Permian Basin divestiture in September 2013 for $31 million, and the Panhandle divestiture in November 2013 for $965 million. Proceeds received from the divestiture of oil and natural gas properties in 2012 included $208 million for the South Louisiana

divestiture in November 2012. In addition, cash used for the exploration, development, and leasehold acquisition of oil and gas properties decreased $358 million from 2012 to 2013. 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.

Net cash used by financing activities of $1.1 billion in 2013 primarily consisted of $1.0 billion used for the redemption of the 8½% senior notes due 2014, the partial redemption of the 7¼% senior notes due 2019 and 7½% senior notes due 2020, and net credit facility repayments of $65 million. Net cash provided by financing activities 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 partial redemption of the 8½% senior notes due 2014 for $331 million, 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.

Capital Expenditures

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Property acquisitions:			
Proved properties	$—	$—	$—
Unproved properties including leasehold acquisition costs	7,117	64,057	204,537
	7,117	64,057	204,537
Exploration:			
Direct costs	111,290	250,302	272,422
Overhead capitalized	18,656	19,157	20,964
	129,946	269,459	293,386
Development:			
Direct costs	197,790	380,496	392,406
Overhead capitalized	15,337	18,627	25,429
	213,127	399,123	417,835
Total capital expenditures[(1)]	$350,190	$732,639	$915,758

(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 $9 million, $6 million, and $3 million recorded during the years ended December 31, 2013, 2012, and 2011, respectively.

We have established a drilling and completion capital budget of $260 million to $270 million (excluding property acquisitions, capitalized overhead, and changes in asset retirement obligations) for 2014, which will be allocated approximately 64% to Ark-La-Tex and 36% to Eagle Ford. 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. In addition, capital expenditures will depend on availability under our Credit Facility or an alternative source of funding. If such funding is unavailable to us, or not available on prudent terms, our expected capital expenditures would be reduced significantly. Such a reduction would have a correspondingly negative impact on our expected production, revenues, and potentially on our reserves. See “Bank Credit Facility” above for a more complete discussion of our ability to borrow under, and need to

amend, the Credit Facility.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2013:

	2014	2015	2016	2017	2018	After 2018	Total
	(In Thousands)						
Bank debt[1]	$1,429	$1,429	$714	$—	$—	$—	$3,572
Senior notes[2]	58,555	58,555	58,555	58,555	58,555	847,659	1,140,434
Derivative liabilities[3]	4,542	—	—	—	—	—	4,542
Other liabilities[4]	7,838	13,736	5,708	5,300	5,258	34,461	72,301
Operating leases[5]	22,655	15,823	15,190	8,174	2,083	7,873	71,798
Unconditional purchase obligations[6]	6,442	5,805	5,700	—	—	—	17,947
Total contractual obligations	$101,461	$95,348	$85,867	$72,029	$65,896	$889,993	$1,310,594

(1) Bank debt consists of commitment and letter of credit fees under our credit facility, based on the $400 million borrowing base, $2 million in outstanding letters of credit, and the fee rates in effect, all as of December 31, 2013, and assuming no changes through the remaining term of the credit facility. There were no borrowings outstanding under the credit facility as of December 31, 2013.

(2) Senior notes consist of the principal obligations and the anticipated interest payments thereon, based on the outstanding senior notes balances as of December 31, 2013, assuming such balances remain outstanding in full until their respective maturities.

(3) Derivative liabilities represent the fair value of our derivative liabilities as of December 31, 2013. 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. In January 2014, we terminated certain drilling rig operating leases for a net loss of approximately $5 million, which will reduce the operating lease obligations shown in the table above by $12 million in 2014, $11 million in 2015, $11 million in 2016, and $6 million in 2017.

(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 2021, totaled approximately $2 million as of December 31, 2013.

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, 2013, 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 Corp., et al. v. El Rucio Land & Cattle Co., et al. (see Item 3 “Legal Proceedings”), we are required to post a supersedeas bond. As of February 19, 2014, we had obtained this supersedeas 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 $36 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 update our quarterly depletion calculations with our quarter-end reserves estimates. See Part I, Item 1, “Business—Reserves” and Note 14 to the Consolidated Financial Statements for a more complete discussion of our estimated proved reserves as of December 31, 2013.

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 natural 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 natural 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 2013, we recorded a ceiling test write-down in our United States cost center totaling $58 million that resulted primarily from the Panhandle divestiture in the fourth quarter of 2013. Given the magnitude of the Panhandle oil and natural gas reserves as a percentage of our total reserves, the divestiture resulted in a $193 million net gain on disposition of assets rather than 100% of the divestiture proceeds reducing capitalized costs, as has typically been done with previous sales of oil and natural gas properties. This smaller reduction of capitalized costs and the loss of future net revenues from the divested proved oil and natural gas reserves were the primary factors causing the ceiling test write-down. In 2012, we recorded ceiling test write-downs in our United States cost center totaling $958 million and in our Italian cost center totaling $35 million. The United States ceiling test write-downs in 2012 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. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by

considering factors such as 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 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 had no proved reserves in South Africa, and therefore no costs being amortized, the impairment was reported as a period expense and was 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. If the reporting unit has a negative carrying value, we perform the second step if it is more likely than not that a goodwill impairment exists. 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. However, 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. Accordingly, we add a control premium to the market capitalization to determine the total fair value of our reporting unit. 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 natural gas properties. To determine the fair value of our oil and natural gas properties, we consider relevant information in market transactions that involve comparable assets.

At the time of our annual 2013 goodwill impairment test, our reporting unit had a negative carrying value. Because of the presence of adverse qualitative factors, including limitations on accessing capital and a sustained decreased share price, we performed the second step of the impairment test. This test did not result in an impairment. Because the Panhandle divestiture represented more than 25% of our total proved reserves at the time the divestiture closed and, therefore, a gain or loss on divestiture was required to be recorded, we allocated $105

million of goodwill to the Panhandle divestiture in determining the gain on the divestiture. Subsequent to the divestiture, we performed an interim impairment test on the remaining goodwill balance, which did not result in an impairment. 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.

Oil and Gas Reserves Estimates

Our estimates of proved reserves are based on the quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government 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 natural gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and natural 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 14 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 losses (gains) on derivative instruments, net” in our Consolidated Statements of Operations. Also included in this line item are the cash settlements, or realized gains and losses, on our derivative instruments.

Due to the volatility of oil, natural gas, and natural gas liquids prices, 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 value of our commodity derivatives based on a hypothetical change in commodity prices.

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 and 2013. 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 $504 million against our deferred tax assets as of December 31, 2013. 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 2015.

Asset Retirement Obligations

Forest has obligations to remove tangible equipment and restore locations at the end of the oil and natural 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 natural 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.

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, amortization, and

certain other items (“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 items including non-cash operating items such as unrealized gains and losses on derivative instruments, which represent changes in the fair values of the derivative instruments, and accretion of asset retirement obligations, all as 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.

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Net earnings (loss) from continuing operations	$73,924	$(1,288,931)	$98,260
Income tax (benefit) expense	(707)	173,437	89,135
Unrealized losses (gains) on derivative instruments, net	30,923	39,126	(39,087)
Interest expense	119,829	141,831	149,755
Gain on asset dispositions, net	(202,023)	—	—
Loss on debt extinguishment, net	48,725	36,312	—
Accretion of asset retirement obligations	2,982	6,663	6,082
Ceiling test write-down of oil and natural gas properties	57,636	992,404	—
Impairment of properties	—	79,529	—
Depreciation, depletion, and amortization	171,557	280,458	219,684
Stock-based compensation	8,875	15,074	20,536
Legal proceeding costs	—	29,251	6,500
Employee-related asset disposition costs	11,178	1,851	—
Rig stacking	9,989	6,604	—
Adjusted EBITDA from continuing operations	$332,888	$513,609	$550,865

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, we use 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.

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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. The table below sets forth our outstanding commodity swaps as of December 31, 2013.

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 2014	70	$4.38	$4,728	3,500	$95.34	$(327)
Calendar 2015	20	4.20	400	—	—	—

Commodity Options

In connection with several natural gas and oil swaps entered into, we granted option instruments (several swaptions and puts) to the swap counterparties in exchange for our receiving premium hedged prices on the natural gas and oil swaps. Under the terms of the swaption agreements, the counterparties have the option to enter into future swaps with us. The swaptions may not be exercised until their expiration dates. Under the terms of the put agreements, the counterparties have the option to put specified quantities of oil to us at specified prices. The puts may be exercised monthly by the counterparties. The table below sets forth the outstanding commodity options as of December 31, 2013.

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 2016	December 2014	10	$4.18	$(810)	—	$—	$—
Oil Swaptions:							
Calendar 2015	December 2014	—	—	—	3,000	100.00	(1,447)
Calendar 2015	December 2014	—	—	—	1,000	106.00	(219)
Calendar 2015	December 2014	—	—	—	1,000	99.75	(495)
Calendar 2015	December 2014	—	—	—	1,000	99.00	(543)
Oil Put Options:							
Monthly Calendar 2014	Monthly Calendar 2014	—	—	—	2,000	70.00	(237)

The estimated fair value at December 31, 2013 of all our commodity derivative instruments based on various inputs, including published forward prices, was a net asset of approximately $1 million.

Due to the volatility of oil and natural gas 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 and natural gas prices used to calculate the fair values of our commodity derivative instruments at December 31, 2013 would decrease the net fair value of our commodity derivative instruments at December 31, 2013 by approximately

$32 million to a net liability of $31 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, 2013 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, 2013

Subsequent to December 31, 2013, through February 19, 2014, we entered into the following derivative instruments:
Commodity Collars

	Natural Gas (NYMEX HH)		
Collar Term	Bbtu Per Day	Hedged Price per MMBtu	
January 2015 - March 2015	20	$ 4.50/5.31	(1)

(1) Represents the hedged floor and ceiling price per MMBtu.

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, 2013, beginning with the fair value of our derivative contracts on December 31, 2012. 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 and natural gas 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, 2013 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, 2012	$18,914	$13,060	$31,974
Net decrease in fair value	(3,612)	(175)	(3,787)
Net cash settlements received	(14,252)	(12,885)	(27,137)
As of December 31, 2013	$1,050	$—	$1,050

Interest Rate Risk

The following table presents principal amounts and related interest rates by year of maturity for our senior notes at December 31, 2013:

	2019	2020	Total
Senior notes:			
Principal (in thousands)	$577,914	$222,087	$800,001
Fixed interest rate	7.25 %	7.50 %	7.32 %
Effective interest rate(1)	7.24 %	7.50 %	7.31 %

(1) The effective interest rate on the 7.25% senior notes due 2019 differs from the fixed interest rate due to the amortization of the related premium 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.

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 26, 2014

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

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$66,192	$1,056
Accounts receivable	35,654	67,516
Derivative instruments	5,192	40,190
Other current assets	6,756	16,318
Total current assets	113,794	125,080
Property and equipment, at cost:		
Oil and natural gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $8,460,589 and $8,237,186	753,079	1,459,312
Unproved	53,645	277,798
Net oil and natural gas properties	806,724	1,737,110
Other property and equipment, net of accumulated depreciation and amortization of $50,058 and $46,908	11,845	17,128
Net property and equipment	818,569	1,754,238
Deferred income taxes	2,230	14,681
Goodwill	134,434	239,420
Derivative instruments	400	8,335
Other assets	48,525	60,108
	$1,117,952	$2,201,862
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$141,107	$164,786
Accrued interest	6,654	23,407
Derivative instruments	4,542	9,347
Deferred income taxes	2,230	14,681
Current portion of long-term debt	—	12
Other current liabilities	12,201	14,092
Total current liabilities	166,734	226,325
Long-term debt	800,179	1,862,088
Asset retirement obligations	22,629	56,155
Derivative instruments	—	7,204
Other liabilities	73,941	92,914
Total liabilities	1,063,483	2,244,686
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 119,399,983 and 118,245,320 shares issued and outstanding	11,940	11,825
Capital surplus	2,554,997	2,541,859
Accumulated deficit	(2,502,070)	(2,575,994)
Accumulated other comprehensive loss	(10,398)	(20,514)
Total shareholders' equity (deficit)	54,469	(42,824)
	$1,117,952	$2,201,862

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2013	2012	2011
Revenues:			
Oil, natural gas, and natural gas liquids sales	$441,341	$605,523	$703,531
Interest and other	331	136	1,026
Total revenues	441,672	605,659	704,557
Costs, expenses, and other:			
Lease operating expenses	76,675	108,027	99,158
Production and property taxes	14,857	34,249	40,632
Transportation and processing costs	11,895	14,633	13,728
General and administrative	54,826	59,262	65,105
Depreciation, depletion, and amortization	171,557	280,458	219,684
Ceiling test write-down of oil and natural gas properties	57,636	992,404	—
Impairment of properties	—	79,529	—
Interest expense	119,829	141,831	149,755
Realized and unrealized losses (gains) on derivative instruments, net	3,786	(72,646)	(88,064)
Other, net	(142,606)	83,406	17,164
Total costs, expenses, and other	368,455	1,721,153	517,162
Earnings (loss) from continuing operations before income taxes	73,217	(1,115,494)	187,395
Income tax (benefit) expense	(707)	173,437	89,135
Net earnings (loss) from continuing operations	73,924	(1,288,931)	98,260
Net earnings from discontinued operations	—	—	44,569
Net earnings (loss)	73,924	(1,288,931)	142,829
Less: net earnings attributable to noncontrolling interest	—	—	4,987
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$73,924	$(1,288,931)	$137,842
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	$.62	$(11.21)	$.86
Earnings from discontinued operations	—	—	.35
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.21
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	$.62	$(11.21)	$.85
Earnings from discontinued operations	—	—	.34
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.19
Amounts attributable to Forest Oil Corporation common shareholders:			
Net earnings (loss) from continuing operations	$73,924	$(1,288,931)	$98,260
Net earnings from discontinued operations	—	—	39,582
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$73,924	$(1,288,931)	$137,842

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Net earnings (loss)	$73,924	$(1,288,931)	$142,829
Other comprehensive income (loss):			
Foreign currency translation losses	—	—	(27,852)
Defined benefit postretirement plans gains (losses), net of tax	10,116	(2,242)	(6,669)
Total other comprehensive income (loss)	10,116	(2,242)	(34,521)
Total comprehensive income (loss)	84,040	(1,291,173)	108,308
Less: total comprehensive loss attributable to noncontrolling interest	—	—	(1,330)
Total comprehensive income (loss) attributable to Forest Oil Corporation common shareholders	$84,040	$(1,291,173)	$109,638

See accompanying Notes to Consolidated Financial Statements.

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, 2011	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
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.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Continued)
(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 December 31, 2012	118,245	11,825	2,541,859	(2,575,994)	(20,514)	(42,824)	—	(42,824)
Employee stock purchase plan	174	17	622	—	—	639	—	639
Restricted stock issued, net of forfeitures	1,355	135	(135)	—	—	—	—	—
Amortization of stock-based compensation	—	—	14,659	—	—	14,659	—	14,659
Other, net	(374)	(37)	(2,008)	—	—	(2,045)	—	(2,045)
Net earnings	—	—	—	73,924	—	73,924	—	73,924
Other comprehensive income	—	—	—	—	10,116	10,116	—	10,116
Balances at December 31, 2013	119,400	$11,940	$2,554,997	$(2,502,070)	$(10,398)	$54,469	$—	$54,469

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,		
	2013	2012	2011
Operating activities:			
Net earnings (loss)	$73,924	$(1,288,931)	$142,829
Less: net earnings from discontinued operations	—	—	44,569
Net earnings (loss) from continuing operations	73,924	(1,288,931)	98,260
Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations:			
Depreciation, depletion, and amortization	171,557	280,458	219,684
Deferred income tax	—	208,975	58,994
Unrealized losses (gains) on derivative instruments, net	30,923	39,126	(39,087)
Ceiling test write-down of oil and natural gas properties	57,636	992,404	—
Impairment of properties	—	79,529	—
Stock-based compensation expense	8,875	15,074	20,536
Accretion of asset retirement obligations	2,982	6,663	6,082
Gain on asset dispositions, net	(202,023)	—	—
Loss on debt extinguishment, net	48,725	36,312	—
Other, net	1,276	6,684	8,114
Changes in operating assets and liabilities:			
Accounts receivable	31,816	11,573	23,236
Other current assets	3,504	2,630	14,314
Accounts payable and accrued liabilities	1,560	(21,164)	(6,470)
Accrued interest and other	(28,996)	2,322	(5,566)
Net cash provided by operating activities of continuing operations	201,759	371,655	398,097
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development, and leasehold acquisition costs	(363,971)	(721,536)	(873,877)
Other fixed assets costs	(1,517)	(9,128)	(6,968)
Proceeds from sales of assets	1,347,116	262,882	121,115
Net cash provided (used) by investing activities of continuing operations	981,628	(467,782)	(759,730)
Financing activities:			
Proceeds from bank borrowings	529,000	1,244,000	160,000
Repayments of bank borrowings	(594,000)	(1,284,000)	(55,000)
Issuance of senior notes, net of issuance costs	—	491,250	—
Redemption of senior notes	(1,037,174)	(330,709)	(285,000)
Proceeds from the exercise of options and from employee stock purchase plan	639	1,117	3,723
Change in bank overdrafts	(14,424)	(24,217)	17,116
Other, net	(2,292)	(3,270)	(14,144)
Net cash (used) provided by financing activities of continuing operations	(1,118,251)	94,171	(173,305)
Cash flows of discontinued operations:			
Operating cash flows	—	—	101,292
Investing cash flows	—	—	(255,470)
Financing cash flows	—	—	478,324

Net cash provided by discontinued operations	—	—	324,146
Effect of exchange rate changes on cash	—	—	(3,476)
Net increase (decrease) in cash and cash equivalents	65,136	(1,956)	(214,268)
Net increase in cash and cash equivalents of discontinued operations	—	—	(289)
Net increase (decrease) in cash and cash equivalents of continuing operations	65,136	(1,956)	(214,557)
Cash and cash equivalents of continuing operations at beginning of year	1,056	3,012	217,569
Cash and cash equivalents of continuing operations at end of year	$66,192	$1,056	$3,012
Cash paid by continuing operations during the year for:			
Interest (net of capitalized amounts)	$130,082	$130,154	$139,311
Income taxes (net of refunded amounts)	(755)	(28,253)	31,782
Non-cash investing activities of continuing operations:			
Increase (decrease) in accrued capital expenditures	$(28,154)	$(37,766)	$27,235
Common stock issued for acquisition of unproved oil and natural gas properties	—	36,431	—

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2013, 2012, and 2011

(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 (sometimes referred to as "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, with its core operational areas being Eagle Ford in South Texas and Ark-La-Tex in Texas, Louisiana, and Arkansas, 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.

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 natural gas properties. Separate cost centers are maintained for each country in which the Company has operations. The Company's primary oil and gas

operations are conducted in the United States. Prior to the spin-off of Lone Pine on September 30, 2011, the Company also had 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, 2013, 2012, and 2011, Forest capitalized $34.0 million, $37.8 million, and $46.4 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 natural gas properties. During the years ended December 31, 2013, 2012, and 2011, Forest capitalized $2.0 million, $7.2 million, and $10.3 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 factors such as 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 had 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.

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.

At December 31, 2013, Forest recorded a ceiling test write-down of its United States cost center totaling $57.6 million, which resulted primarily from the Panhandle divestiture. Given the magnitude of the Panhandle oil and natural gas reserves as a percentage of Forest’s total reserves, the divestiture resulted in a $193.0 million net gain on disposition of assets rather than 100% of the divestiture proceeds reducing capitalized costs, as has typically been done with previous sales of oil and natural gas properties. This smaller reduction of capitalized costs and the loss of future net revenues from the divested proved oil and natural gas reserves were the primary factors causing the ceiling test write-down. See Note 2 for more information on the Panhandle divestiture.

In 2012, Forest recorded ceiling test write-downs of its United States cost center totaling $957.6 million and its 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 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. As noted above, a gain was recognized on the Panhandle divestiture in 2013. See Note 2 for more information on the Panhandle divestiture.

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.

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 natural gas properties.

The following table summarizes the activity for the Company's asset retirement obligations for the periods indicated:

	Year Ended December 31,	
	2013	2012
	(In Thousands)	
Asset retirement obligations at beginning of period	$58,585	$78,938
Accretion expense	2,982	6,663
Liabilities incurred	2,362	1,412
Liabilities settled	(2,726)	(5,650)
Disposition of properties	(42,082)	(27,418)
Revisions of estimated liabilities	6,234	4,640
Asset retirement obligations at end of period	25,355	58,585
Less: current asset retirement obligations	(2,726)	(2,430)
Long-term asset retirement obligations	$22,629	$56,155

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

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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, 2013 and 2012, the Company had gas imbalance liabilities of $4.3 million and $7.5 million, respectively, and gas imbalance assets of $3.4 million and $6.7 million, respectively.

In 2013, sales to two purchasers were approximately 23%, or $102.5 million, and 17%, or $73.5 million, respectively, of the Company's total revenues. 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. 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,	
	2013	2012
	(In Thousands)	
Oil, natural gas, and NGL sales	$22,293	$50,679
Joint interest billings	5,222	5,845
Tax incentive refunds due from Texas	3,763	6,836
Other	5,494	5,619
Allowance for doubtful accounts	(1,118)	(1,463)
Total accounts receivable	$35,654	$67,516

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.

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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 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 and cash-settled performance units issued under Forest's stock incentive plans do not participate in dividends. Share-settled performance units issued under Forest's stock incentive plans do not participate in dividends in their current form. Holders of these 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. Share-settled 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 share-settled phantom stock units, and unvested share-settled 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 per share is computed using the more dilutive of the treasury stock method or the two-class method. Under the treasury stock method, the dilutive effect of potential common shares is computed by assuming common shares are issued for these securities at the beginning of the period, with the assumed proceeds from exercise, which include average unamortized stock-based compensation costs, 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 per share computation. The number of contingently issuable shares pursuant to the outstanding share-settled performance units is included in the denominator of the computation of diluted earnings 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, 2013 and 2011 as their inclusion would have an antidilutive effect.

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,								
	2013			2012			2011		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In Thousands)								
Net earnings (loss)	$73,924	$—	$73,924	$(1,288,931)	$—	$(1,288,931)	$98,260	$44,569	$142,829
Less: net earnings attributable to noncontrolling interest	—	—	—	—	—	—	—	(4,987)	(4,987)
Less: net earnings attributable to participating securities	(2,099)	—	(2,099)	—	—	—	(2,037)	(821)	(2,858)
Net earnings (loss) attributable to common stock for basic earnings (loss) per share	71,825	—	71,825	(1,288,931)	—	(1,288,931)	96,223	38,761	134,984
Adjustment for liability classified stock-based compensation awards	—	—	—	—	—	—	—	(707)	(707)
Net earnings (loss) for diluted earnings (loss) per share	$71,825	$—	$71,825	$(1,288,931)	$—	$(1,288,931)	$96,223	$38,054	$134,277

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Weighted average common shares outstanding during the period for basic earnings (loss) per share	116,125	114,958	111,690
Dilutive effects of potential common shares	—	—	1,178
Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares, for diluted earnings (loss) per share	116,125	114,958	112,868

Stock-Based Compensation

Compensation cost is measured at the grant date based on the fair value of the awards (stock options, restricted stock, share-settled performance units, employee stock purchase plan rights) or is measured at the reporting date based on the fair value of the awards (cash-settled phantom stock units and cash-settled performance units), and is recognized on a straight-line basis over the requisite service period (usually the vesting period). Compensation cost for awards with only service conditions that have a graded vesting schedule is recognized on a straight-line basis over the requisite service period for each separately vesting portion of the award.

Derivative Instruments

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

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, 2013 and 2012 totaled $13.4 million and $27.0 million, respectively, and are being amortized over the life of the respective debt instruments. In connection with the early repayment of senior notes in 2013, $8.9 million of unamortized debt issue costs were written-off.

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 $2.2 million and $4.2 million of materials and supplies as of December 31, 2013 and 2012, 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 allocates a portion of goodwill to divestitures of more than 25% of the Company’s total proved reserves. During the year ended December 31, 2013, the Company allocated $105.0 million of goodwill to the Panhandle divestiture. See Note 2 for more information regarding this divestiture. The Company had no goodwill impairments for the years ended December 31, 2013, 2012, and 2011.

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 gains and losses. See Note 7 for more information regarding Forest’s defined benefit postretirement plans.

The components of other comprehensive income (loss), both before-tax and net-of-tax, for the years ended December 31, 2013, 2012, and 2011 are as follows:

	Before-Tax	Tax (Expense) / Benefit	Net-of-Tax
	(In Thousands)		
Year Ended December 31, 2013:			
Defined benefit postretirement plans			
Net periodic benefit cost components arising during the period	$8,742	$—	$8,742
Actuarial losses reclassified from accumulated other comprehensive loss and included in net periodic benefit cost	1,374	—	1,374
Other comprehensive income	$10,116	$— [(1)]	$10,116
Year Ended December 31, 2012:			
Defined benefit postretirement plans			
Net periodic benefit cost components arising during the period	$(3,191)	$(323)	$(3,514)
Actuarial losses reclassified from accumulated other comprehensive loss and included in net periodic benefit cost	1,155	117	1,272
Other comprehensive loss	$(2,036)	$(206)	$(2,242)
Year Ended December 31, 2011:			
Defined benefit postretirement plans			
Net periodic benefit cost components arising during the period	$(11,058)	$3,979	$(7,079)
Actuarial losses reclassified from accumulated other comprehensive loss and included in net periodic benefit cost	641	(231)	410
	(10,417)	3,748	(6,669)
Foreign currency translation losses			
Foreign currency translation losses arising during the period	(27,852)	—	(27,852)
Amounts reclassified from accumulated other comprehensive loss	—	—	—
	(27,852)	—	(27,852)
Other comprehensive loss	$(38,269)	$3,748	$(34,521)

(1) Tax expense of $3.6 million for the year ended December 31, 2013 is offset by an equal decrease in the valuation allowance.

The components of accumulated other comprehensive income (loss) attributable to Forest Oil Corporation common shareholders for the years ended December 31, 2013, 2012, and 2011 are as follows:

	Foreign Currency Translation	Defined Benefit Postretirement Plans	Accumulated Other Comprehensive Income (Loss)
	(In Thousands)		
Balance at December 31, 2010	$93,667	$(11,603)	$82,064
Changes in ownership interest in Lone Pine Resources	(72,132)	—	(72,132)
Other comprehensive losses arising during the period, before reclassifications	(21,535)	(7,079)	(28,614)
Amounts reclassified from accumulated other comprehensive loss	—	410	410
Other comprehensive loss	(21,535)	(6,669)	(28,204)
Balance at December 31, 2011	—	(18,272)	(18,272)
Other comprehensive losses arising during the period, before reclassifications	—	(3,514)	(3,514)
Amounts reclassified from accumulated other comprehensive loss	—	1,272	1,272
Other comprehensive loss	—	(2,242)	(2,242)
Balance at December 31, 2012	—	(20,514)	(20,514)
Other comprehensive gains arising during the period, before reclassifications	—	8,742	8,742
Amounts reclassified from accumulated other comprehensive loss	—	1,374	1,374
Other comprehensive income	—	10,116	10,116
Balance at December 31, 2013	$—	$(10,398)	$(10,398)

(2) PROPERTY AND EQUIPMENT:

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

	December 31, 2013	2012
	(In Thousands)	
Oil and natural gas properties:		
Proved	$9,213,668	$9,696,498
Unproved	53,645	277,798
Accumulated depletion[1]	(8,460,589)	(8,237,186)
Net oil and natural gas properties	806,724	1,737,110
Other property and equipment:		
Furniture and fixtures, leasehold improvements, computer hardware and software, and other equipment	61,903	64,036
Accumulated depreciation and amortization	(50,058)	(46,908)
Net other property and equipment	11,845	17,128
Total net property and equipment	$818,569	$1,754,238

(1) Includes inception-to-date ceiling test write-downs.

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The following table sets forth a summary as of December 31, 2013 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 (In Thousands)	2013	2012	2011	2010 and Prior
Acquisition costs	$48,095	$5,078	$4,155	$2,515	$36,347
Exploration costs	5,550	4,722	194	57	577
Total unproved oil and natural gas properties	$53,645	$9,800	$4,349	$2,572	$36,924

The majority of the unproved oil and natural gas property costs, which are not subject to depletion, relate to oil and natural 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, 2013 will be reclassified to proved properties within ten years.

Divestitures

Texas Panhandle

In October 2013, Forest entered into an agreement to sell all of its oil and natural gas properties located in the Texas Panhandle for $1.0 billion in cash. The purchase price was adjusted at closing on November 25, 2013 to $944.1 million in order to, among other things, reflect an economic effective date of October 1, 2013. Subsequent to closing, Forest received an additional $21.0 million for post-closing title curative work completed, for total cash proceeds received to-date of $965.1 million. As of December 31, 2013, there is $32.9 million remaining in escrow, which Forest may receive as consents-to-assign are received and further post-closing title curative work is completed. Of the $32.9 million escrow balance, $10.0 million supports post-closing indemnities that Forest may owe to the buyer under the terms of the purchase and sale agreement. Any of the $10.0 million remaining in escrow at the one-year anniversary of the closing will be paid to Forest. Forest used a portion of the Panhandle divestiture proceeds to repay the balance outstanding on its credit facility and to redeem $700.0 million aggregate principal amount of its 7¼% senior notes due 2019 and 7½% senior notes due 2020.

In connection with the Panhandle divestiture, Forest incurred exit costs consisting of one-time employee termination benefits and other associated costs, as shown in the following table.

	One-Time Employee Termination Benefits (In Thousands)	Other Associated Costs[1]	Total
Total expected amount[2]	$4,541	$7,967	$12,508
Amount paid during 2013	2,915	2,128	5,043
December 31, 2013 liability balance[3]	1,095	5,840	6,935

(1) Other associated costs consist of financial advisor fees and retention bonuses paid to certain employees.

(2) Of the $12.5 million total expected amount, $5.0 million was recognized in "General and administrative" expense and $5.8 million was recognized in "Other, net" in the Consolidated Statement of Operations for the year ended December 31, 2013. Additionally, $1.1 million was capitalized in "Oil and natural gas properties" in the Consolidated Balance Sheet pursuant to the full cost method of accounting. The remaining $.5 million will be accrued in 2014 over the remaining retention period of the affected employees.

(3)

The December 31, 2013 estimated liability balance is included in “Accounts payable and accrued liabilities” in the Consolidated Balance Sheet, and Forest expects it will be paid during the first half of 2014.

Under the full cost method of accounting, sales of oil and natural gas properties are typically accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves attributable to a cost center. A significant alteration would not ordinarily be expected to occur for sales involving less than 25% of the reserve quantities of a given cost center. The proved reserves associated with the Panhandle divestiture represented more than 25% of Forest's total proved reserves at the time the divestiture closed. Forest concluded that accounting for the divestiture as an adjustment of capitalized costs would significantly alter the relationship between capitalized costs and proved reserves. Therefore, a gain was recognized on the divestiture. The historical net book value of Forest's oil and natural gas properties at the time of sale was allocated between the properties divested and properties retained based on proved reserves. As discussed in Note 1—"Goodwill", Forest allocated $105.0 million of goodwill to the Panhandle divestiture in determining the gain on the divestiture. The net gain recognized on the divestiture for the year ended December 31, 2013 was $193.0 million.

South Texas

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 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 cash proceeds of $320.9 million. Forest used the proceeds from this divestiture to redeem the remaining $300.0 million of its 8½% senior notes due 2014. In connection with the South Texas divestiture, Forest incurred one-time employee termination benefit costs of $7.5 million ($5.7 million net of capitalization), which are included in "General and administrative" expense in the Consolidated Statement of Operations and were paid in full during 2013, with no further one-time employee termination benefit costs expected to be made for this specific divestiture.

Permian Basin

In August 2013, Forest entered into an agreement to sell a portion of its largely undeveloped acreage position located in Crockett County in the Permian Basin of West Texas. This transaction closed on September 10, 2013, and Forest received net cash proceeds of $31.4 million, after customary purchase price adjustments. Forest retained a Permian Basin acreage position located in Pecos and Reeves Counties, Texas. Forest used the proceeds from this divestiture to reduce outstanding borrowings under its credit facility.

South Louisiana

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 cash proceeds of $211.3 million.

Gas Gathering Assets

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. This transaction closed on October 31, 2012, and Forest received net cash proceeds of $28.8 million, after customary purchase price adjustments. At the time of closing, there were up to $9.0 million of additional performance payments that Forest could earn contingent upon future activity, including the number of additional wells drilled by Forest and connected to the buyer's gathering facilities. During year ended December 31, 2013, Forest earned and received $2.5 million of these performance payments. As of December 31, 2013, there are $6.0 million of contingent performance payments that may still be earned. In conjunction with the sale, Forest entered into a ten-year natural gas gathering agreement with the buyer under which Forest pays market-based gathering rates and has committed 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 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.

South Africa

In December 2012, Forest entered into an agreement with a third-party whereby Forest would receive $9.1 million in exchange for Forest abandoning its exploration right covering Block 2C in South Africa, contingent upon, among other things, the approval of the abandonment by the government of South Africa. Upon completion of certain contractual requirements, Forest received the $9.1 million in December 2013 and recorded a gain of $9.0 million, net of transaction costs, in other income within the "Other, net" line item in the Consolidated Statement of Operations for the year ended December 31, 2013 since Forest had no proved reserves in South Africa and fully impaired its unproved properties in South Africa in 2012.

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. Following approval of the sale by the government 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 set forth in the agreement.

Miscellaneous

During the year ended December 31, 2013, Forest also sold miscellaneous oil and natural gas properties for proceeds of $17.5 million. During the years ended December 31, 2012 and 2011, Forest also sold miscellaneous U.S. oil and natural gas properties for total proceeds of $25.6 million and $121.0 million, respectively.

Acquisition and Development Agreement

In April 2013, Forest entered into an Acquisition and Development Agreement ("ADA") with a third-party for the future development of Forest's Eagle Ford acreage in Gonzales County, Texas. Under the terms of the ADA, the third-party will pay a $90.0 million drilling carry in the form of future drilling and completion services and related development capital in exchange for a 50% working interest in Forest's Eagle Ford acreage position. Upon completion of the phased contribution of the drilling carry, Forest and the third-party will participate in future drilling on a 50/50 basis. The ADA applies to wells spud on or subsequent to November 28, 2012, none of which had been placed on production prior to April 1, 2013, and Forest retained all of its interests in wells and production that were spud prior to November 28, 2012. Forest is the operator of the drilling program. As of December 31, 2013, Forest had realized $61.1 million of the drilling carry and currently expects that it will be fully realized in 2014.

(3) DEBT:

The components of debt are as follows:

	December 31, 2013			December 31, 2012		
	Principal	Unamortized Premium	Total	Principal	Unamortized Premium (Discount)	Total
	(In Thousands)					
Credit facility	$—	$—	$—	$65,000	$—	$65,000
7% senior subordinated notes due 2013[1]	—	—	—	12	—	12
8½% senior notes due 2014[2]	—	—	—	300,000	(3,277)	296,723
7¼% senior notes due 2019[3]	577,914	178	578,092	1,000,000	365	1,000,365
7½% senior notes due 2020[4]	222,087	—	222,087	500,000	—	500,000
Total debt	800,001	178	800,179	1,865,012	(2,912)	1,862,100
Less: current portion of long-term debt	—	—	—	(12)	—	(12)
Long-term debt	$800,001	$178	$800,179	$1,865,000	$(2,912)	$1,862,088

(1) In June 2013, Forest redeemed the 7% senior subordinated notes due 2013 at their maturity.

(2) In March 2013, Forest redeemed the 8½% senior notes due 2014 at 107.11% of par, recognizing a loss of $25.2 million upon redemption.

(3) In November 2013, Forest redeemed $422.1 million in principal amount of 7¼% senior notes due 2019 at 102.77% of par, recognizing a net loss of $14.7 million upon redemption.

(4) In November 2013, Forest redeemed $277.9 million in principal amount of 7½% senior notes due 2020 at 101.50% of par, recognizing a loss of $8.8 million upon redemption.

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.

On September 12, 2013, the Company entered into the First Amendment to the Credit Facility (the “First Amendment”), which was effective as of that date. The First Amendment amended, among other things, the permitted ratio of total debt to EBITDA and the definition of total debt used in the ratio calculation, and reduced the borrowing base, which governs Forest’s availability under the Credit Facility, to $700.0 million.

As of December 31, 2013, the borrowing base under the Credit Facility was $400.0 million. 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 natural gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders’ customary practices for oil and natural gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. 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. The borrowing base is also subject to automatic adjustment if Forest or any of its Restricted Subsidiaries sell oil and natural gas properties having a fair market value, including any economic loss of unwinding any related hedging agreement, 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 February 2013 sale of Forest's South Texas properties resulted in a $170.0 million reduction to the borrowing base effective February 15, 2013, and the November 2013 sale of Forest's Panhandle properties resulted in a $300.0 million reduction to the borrowing base effective November 25, 2013. See Note 2 for more information regarding Forest's property divestitures. The next scheduled semi-annual redetermination of the borrowing base will occur on or about May 1, 2014. 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 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 natural gas properties and related assets. If Forest's corporate credit ratings issued by Moody's and Standard &Poor's 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 First Amendment to the Credit Facility provides that Forest will not permit its ratio of total debt to EBITDA (as adjusted for non-cash charges) calculated for the preceding four consecutive fiscal quarter period then most recently ended (i) for any time on or before September 11, 2013, to be greater than 4.50 to 1.00, (ii) for any time after September 11, 2013 and on or before March 31, 2014 to be greater than 5.00 to 1.00, (iii) for any time after April 1, 2014 and on or before June 30, 2014 to be greater than 4.75 to 1.00, and (iv) for any time after June 30, 2014, to be greater than 4.50 to 1.00. The First Amendment also amends the definition of total debt such that, during any period of four fiscal quarters that includes the calendar quarter in which the Panhandle divestiture closed, any cash proceeds from the Panhandle divestiture that are reported on Forest's consolidated balance sheet on such date are subtracted from total debt. Depending on Forest's overall level of indebtedness, this covenant may limit Forest's ability to borrow funds as needed under the Credit Facility. Forest's ratio of total debt to EBITDA for the four consecutive fiscal quarter period ended December 31, 2013, as calculated in accordance with the Credit Facility, was 4.3. Based on Forest's current projections, Forest expects the ratio of total debt to EBITDA to exceed the maximum allowed under the Credit Facility sometime during the second or third quarter of 2014 if it does not obtain an additional amendment to the Credit Facility. Forest has initiated discussions to that effect with the administrative agent of the Credit Facility and, with no amounts currently drawn against the facility, believes that it will be able to obtain such an amendment prior to the ratio exceeding the maximum amount currently allowed. If Forest fails to obtain an amendment, the Credit Facility could be terminated. However, Forest believes it can obtain alternative sources of debt financing sufficient for its needs, including securing liens against its properties or selling additional properties. Additionally, if necessary, Forest has the ability to slow or cease the occurrence of certain capital and operational expenditures, including those related to initiating new drilling programs, to preserve its available cash until these other sources of funding become available at prudent terms.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated with the resultant termination of the facility. 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. In addition, certain

events of default under the Credit Facility will result in acceleration of the indebtedness under the Credit Facility, and termination of the 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, 2013, there were no outstanding borrowings under the Credit Facility 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 $397.9 million. 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.

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 were 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. In March 2013, Forest redeemed the remaining $300.0 million of 8½% Notes at 107.11% of par, recognizing a loss of $25.2 million upon redemption, using proceeds from the South Texas divestiture 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 %

In November 2013, Forest carried out a tender offer to purchase up to $700.0 million aggregate principal amount of its 7¼% Notes and its 7½% senior notes using proceeds from the Panhandle divestiture. The tender offer for the 7¼% Notes was issued at 102.77% of par and Forest purchased $422.1 million of the 7¼% Notes, recognizing a net loss of $14.7 million upon redemption.

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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. 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.

In November 2013, Forest carried out a tender offer to purchase up to $700.0 million aggregate principal amount of its 7¼% Notes and its 7½% Notes using proceeds from the Panhandle divestiture. The tender offer for the 7½% Notes was issued at 101.50% of par and Forest purchased $277.9 million of the 7½% Notes, recognizing a loss of $8.8 million upon redemption.

Forest's 8½% Notes, 7¼% Notes, and 7½% Notes were fully and unconditionally guaranteed by a 100%-owned subsidiary of Forest, Forest Oil Permian Corporation (the "Guarantor Subsidiary"). Substantially all of the property of the Guarantor Subsidiary was sold in the Panhandle divestiture and, as a result, the Guarantor Subsidiary was merged into Forest effective December 31, 2013. As such, the guarantee no longer exists.

Principal Maturities

Principal maturities of Forest's debt at December 31, 2013 are as follows:

	Principal Maturities (In Thousands)
2014	$—
2015	—
2016	—
2017	—
2018	—
Thereafter	800,001

(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,		
	2013	2012	2011
	(In Thousands)		
Current:			
Federal	$—	$(34,733)	$(201)
Foreign	—	—	28,921
State	(707)	(805)	1,421
	(707)	(35,538)	30,141
Deferred:			
Federal	—	202,552	56,482
State	—	6,423	2,512
	—	208,975	58,994
Total income tax	$(707)	$173,437	$89,135

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
United States federal	$65,167	$(1,013,801)	$188,421
Foreign	8,050	(101,693)	(1,026)
	$73,217	$(1,115,494)	$187,395

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,		
	2013	2012	2011
	(In Thousands)		
Federal income tax at 35% of earnings from continuing operations before income taxes	$25,626	$(390,423)	$65,947
State income taxes, net of federal income tax benefits	740	(11,211)	2,214
Change in valuation allowance	(67,606)	575,570	—
Change in non-tax deductible goodwill	37,937	—	—
Stock-based compensation	4,002	484	—
Canadian dividend tax, net of U.S. tax benefit	—	—	18,460
Effect of federal, state, and foreign tax on permanent differences	638	3,026	4,025
Other	(2,044)	(4,009)	(1,511)
Total income tax	$(707)	$173,437	$89,135

Net Deferred Tax Assets and Liabilities

The components of net deferred tax assets and liabilities at December 31, 2013 and 2012 are as follows:

	December 31, 2013	2012
	(In Thousands)	
Deferred tax assets:		
Property and equipment[1]	$161,450	$353,352
Accrual for postretirement benefits	3,193	3,134
Stock-based compensation accruals	9,592	10,748
Net operating loss carryforwards	274,177	157,103
Alternative minimum tax credit carryforward	49,409	49,409
Other	23,721	32,278
Total gross deferred tax assets	521,542	606,024
Less valuation allowance	(504,458)	(575,570)
Net deferred tax assets	17,084	30,454
Deferred tax liabilities:		
Unrealized gains on derivative instruments, net	(1,994)	(17,429)
Amortization of deferred gain on rig sales	(12,724)	(10,472)
Other	(2,366)	(2,553)
Total gross deferred tax liabilities	(17,084)	(30,454)
Net deferred tax assets	$—	$—

(1) Includes deferred tax assets of $25.5 million and $28.3 million related to Italy and South Africa as of December 31, 2013 and 2012, respectively.

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

	December 31, 2013	2012
	(In Thousands)	
Current deferred tax liabilities	$(2,230)	$(14,681)
Non-current deferred tax assets	2,230	14,681
Net deferred tax assets	$—	$—

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards (“NOLs”) at December 31, 2013 were approximately $765.5 million, with $32.2 million of NOLs limited under Section 382 of the Internal Revenue Code scheduled to expire in 2019 and 2020 and the remaining scheduled to expire after 2029. Forest completed a Section 382 study in 2009. Because of the full valuation allowance placed against its deferred tax assets, Forest has not yet updated this study. Additionally, as of December 31, 2013, the Company had state income tax NOLs of approximately $152.2 million, which, if unused, will expire between 2014 and 2031.

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

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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, 2013, 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,		
	2013	2012	2011
	(In Thousands)		
Gross unrecognized tax benefits at beginning of period	$859	$2,829	$3,345
Increases as a result of tax positions taken during a prior period	31	—	—
Decreases as a result of tax positions taken during a prior period	—	(1,970)	(516)
Gross unrecognized tax benefits at end of period	$890	$859	$2,829

Income Tax Receivables

As of December 31, 2013 and 2012, Forest had a non-current income tax receivable of $20.7 million which is included in "Other assets" in the Consolidated Balance Sheets.

(5) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2013, the Company had 200.0 million shares of common stock, par value $.10 per share, authorized and 119.4 million shares issued and outstanding.

In February 2012, the Company issued 2.7 million shares of common stock, valued at $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 Certificate 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.

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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 (benefit) expense" 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 its credit facility to repay its 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.

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)

(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 9.5 million shares. As of December 31, 2013, the Company had 4.0 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, 2013.

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Compensation Costs

The table below sets forth stock-based compensation related to Forest's continuing operations for the years ended December 31, 2013, 2012, and 2011, and the remaining unamortized amounts and weighted average amortization period as of December 31, 2013.

	Stock Options	Restricted Stock	Performance Units	Phantom Stock Units	Total[1][2]
	(In Thousands)				
Year ended December 31, 2013:					
Total stock-based compensation costs	$—	$12,149	$2,288	$3,946	$18,383
Less: stock-based compensation costs capitalized	—	(5,355)	(431)	(2,022)	(7,808)
Stock-based compensation costs expensed	$—	$6,794	$1,857	$1,924	$10,575
Unamortized stock-based compensation costs as of December 31, 2013[3]	$—	$9,611	$3,517	$4,662	$17,790
Weighted average amortization period remaining as of December 31, 2013	—	1.5 years	1.9 years	1.8 years	1.6 years
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
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

(1) The Company also maintains an employee stock purchase plan (which is not included in the table) under which $.2 million, $.4 million, and $.5 million of compensation costs were recognized for the years ended December 31, 2013, 2012, and 2011, respectively.

(2) In connection with the 2013 divestitures of the South Texas and Texas Panhandle oil and natural gas properties, Forest incurred $4.9 million ($2.1 million net of capitalized amounts) in stock-based compensation costs due to accelerated vesting of involuntarily terminated employees' awards. See Note 2 for more information regarding these divestitures.

(3) The unamortized stock-based compensation costs for liability-based awards are based on the closing price of Forest's common stock at the reporting period end.

Stock Options

The following table summarizes stock option activity in the Stock-based Compensation Plans for the years ended December 31, 2013, 2012, and 2011.

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Options Exercisable
Outstanding at January 1, 2011	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
Granted	—	—		
Exercised	—	—	—	
Cancelled	(239,610)	19.55		
Outstanding at December 31, 2013	631,206	$17.21	$—	631,206

(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 in 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, 2013:

	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)
$11.02 - 12.20	131,223	0.18	$11.12	$—
12.21 - 13.47	27,383	0.30	12.80	—
13.48 - 13.68	205,508	0.76	13.56	—
13.69 - 24.30	128,565	2.02	19.54	—
24.31 - 27.90	138,527	2.76	27.11	—
$11.02 - 27.90	631,206	1.31	$17.21	$—

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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, 2013, 2012, and 2011.

	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	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)
Unvested at January 1, 2011	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[1]	—			233,740			225,004		
Vested due to spin-off[2]	—			(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	
Awarded	2,163,877	6.04		1,182,500	5.47		1,808,701	6.28	
Vested	(1,286,322)	18.07	6,911	(203,240)	19.60	—	(577,201)	10.60	2,881
Forfeited	(808,650)	11.47		(407,300)	9.68		(468,418)	8.03	
Unvested at December 31, 2013	2,790,542	$10.23		1,511,140	$8.48		1,924,819	$6.75	

(1) 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 in 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 in 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.

(2) 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 and performance unit agreements, and, therefore, all such

awards held by Lone Pine employees vested on September 30, 2011. The phantom stock awards were settled in cash by Lone Pine. No shares were deliverable under the performance unit agreement. No Forest restricted stock awards were held by Lone Pine employees at the time of the spin-off.

Restricted Stock

The grant date fair value of restricted stock is determined by averaging the high and low stock price of a share of Forest common stock as published by the New York Stock Exchange on the date of grant. Of the unvested restricted stock as of December 31, 2013, 851,526 shares, which were granted in 2013, vest in increments of one-third on each of the first three anniversary dates of the grant. All other unvested shares of restricted stock cliff vest on the third anniversary of the date of grant. Restricted stock may vest earlier upon a qualifying disability, death, certain involuntary terminations, or a change in control of the Company in accordance with the terms of the underlying agreement.

Performance Units

Forest grants performance units to its officers. Under the terms of the award agreements, each performance unit represents a contractual right to receive either one share of Forest's common stock or the cash value of one share of Forest's common stock, depending on the particular agreement, provided that the actual number of shares or cash equivalent amount 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. The cash-based performance units are accounted for as a liability within the Consolidated Financial Statements. Of the unvested performance units at December 31, 2013, 706,000, which were granted in 2013, are cash-based and the remaining 805,140 are share-based. Like restricted stock, performance units may vest earlier due to certain circumstances, as discussed above.

Phantom Stock Units

The grant and reporting date fair values of the phantom stock units are determined by averaging the high and low stock price of a share of Forest common stock as published by the New York Stock Exchange on the applicable date. All of the unvested phantom stock units at December 31, 2013 must be settled in cash and, therefore, are accounted for as a liability within the Consolidated Financial Statements. All of the phantom stock units that vested during 2013 were settled in cash. In 2012, 6,080 phantom stock units were settled in shares of common stock and 602,463 phantom stock units were settled in cash. In 2011, 5,500 phantom stock units were settled in shares of common stock and 393,357 phantom stock units were settled in cash.

Of the unvested phantom stock units at December 31, 2013, (i) 152,393 were granted in 2011 and 851,426 were granted in 2013 and vest in one-third increments on each of the first three anniversaries of the date of grant, (ii) 493,000 were granted in 2013 and cliff vest on the third anniversary of the date of the award, (iii) and 378,000 were granted in 2012 and 50,000 were granted in 2013 and vest over a four-year period in accordance with the following schedule: (a) 10% on the first anniversary of the grant date; (b) 20% on the second anniversary of the grant date; (c) 30% on the third anniversary of the grant date; and (d) 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.

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to 1.6 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, 2013, the Company had .7 million shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2013, 2012, and 2011 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,		
	2013	2012	2011
Expected option life	3 months	3 months	3 months
Risk free interest rates	.02% - .08%	.02% - .10%	.02% - .15%
Estimated volatility	42%	46%	59%
Dividend yield	0%	0%	0%
Weighted average fair market value of purchase rights granted	$1.29	$2.43	$5.00

(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 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, 2013, 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 the following amounts:

	2014	2015	2016	2017	2018	2019-2023
	(In Thousands)					
Forest Pension Plan[1]	$2,336	$2,291	$2,230	$2,159	$2,116	$9,433
Wiser Pension Plan[1]	867	861	851	837	818	3,833
SERP	133	129	124	120	114	490
Postretirement Benefits Plan	727	713	706	726	734	3,849

(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 2014 totaling $1.7 million to the Plans and $.6 million to the Postretirement Benefits Plan, net of retiree contributions, as applicable.

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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	
	2013	2012	2013	2012
	(In Thousands)			
Benefit obligation at the beginning of the year	$46,017	$44,755	$17,227	$13,498
Service cost	—	—	1,094	1,131
Interest cost	1,329	1,554	603	547
Actuarial (gain) loss	(2,983)	2,902	(2,935)	2,613
Benefits paid	(3,285)	(3,194)	(602)	(619)
Retiree contributions	—	—	49	57
Benefit obligation at the end of the year	$41,078	$46,017	$15,436	$17,227

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.

	December 31, 2013				December 31, 2012			
	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[1]	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[1]
	(In Thousands)							
Cash and cash equivalents	$81	$36	$—	$117	$3	$148	$—	$151
Investment funds—equities:								
Research equity portfolio[2]	—	12,159	—	12,159	—	10,403	—	10,403
International stock funds[3]	12,246	—	—	12,246	10,503	—	—	10,503
Investment funds—fixed income:								
Short-term fund[4]	1,939	—	—	1,939	1,998	—	—	1,998
Bond fund[5]	4,802	—	—	4,802	4,813	—	—	4,813
Oil and gas royalty	—	—	153	153	—	—	138	138

interests[6]	$19,068	$12,195	$153	$31,416	$17,317	$10,551	$138	$28,006

(1) The total fair value of the Pension Plans' assets of $31.4 million as of December 31, 2013 does not include net accrued expenses of $.1 million. The total fair value of the Pension Plans' assets of $28.0 million as of December 31, 2012 does not include net accrued expenses of $.2 million.

(2) 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, 2013, the sector weighting of this fund was comprised of the following: information technology (19%), financials (16%), health care (15%), consumer discretionary (11%), industrials (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.

(3) 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, 2013, the sector weighting of this fund, which seeks diversification across regions, countries, and market sectors, was comprised of the following: financials (24%), health care (16%), information technology (15%), consumer discretionary (13%), industrials (11%), and other (21%). 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, 2013, 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 (27%), information technology (18%), consumer staples (18%), consumer discretionary (11%), and other (26%). The third fund seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets equity securities. As of December 31, 2013, 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: financials (17%), materials (14%), consumer discretionary (14%), information technology (13%), industrials (13%), energy (12%), and other (17%). 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.

(4) 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, 2013, the sector weighting of this fund was comprised of the following: government related (28%), investment grade (23%), mortgage (13%), and other (36%). 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.

(5) 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, 2013, the sector weighting of this fund was comprised of the following: government-related (42%), mortgage (33%), and other (25%). The second fund seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets debt securities. As of December 31, 2013, 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 (40%), corporates (28%), inflation linked (22%), and sovereign U.S. dollar denominated (10%). 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.

(6) 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	
	2013	2012	2013	2012
	(In Thousands)			

Fair value of plan assets at beginning of the year	$27,791	$25,957	$—	$—
Actual return on plan assets	4,736	4,048	—	—
Retiree contributions	—	—	49	57
Employer contribution	2,107	980	553	562
Benefits paid	(3,285)	(3,194)	(602)	(619)
Fair value of plan assets at the end of the year	$31,349	$27,791	$—	$—

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,	
	2013	2012
	Oil and Gas Royalty Interests	
	(In Thousands)	
Balance at beginning of period	$138	$198
Actual return on plan assets	51	119
Purchases, sales, and settlements (net)	(36)	(179)
Transfers in and/or out of Level 3	—	—
Balance at end of period	$153	$138

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 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	
	2013	2012	2013	2012
Fixed income securities	22%	24%	21%	25%
Equity securities	77%	75%	78%	74%
Other	1%	1%	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	
	2013	2012	2013	2012
	(In Thousands)			
Excess of benefit obligation over plan assets	$(9,728)	$(18,225)	$(15,436)	$(17,227)
Unrecognized actuarial loss	18,025	24,811	2,303	5,633
Net amount recognized	$8,297	$6,586	$(13,133)	$(11,594)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—current	$(133)	$—	$(641)	$—
Accrued benefit liability—noncurrent	(9,595)	(18,225)	(14,795)	(17,227)
Accumulated other comprehensive income—net actuarial loss	18,025	24,811	2,303	5,633
Net amount recognized	$8,297	$6,586	$(13,133)	$(11,594)

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

	December 31,	
	2013	2012
	(In Thousands)	
Projected benefit obligation	$41,078	$46,017
Accumulated benefit obligation	41,078	46,017
Fair value of plan assets	31,349	27,791

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		
	2013	2012	2011	2013	2012	2011
	(Dollar Amounts In Thousands)					
Service cost	$—	$—	$—	$1,094	$1,131	$825
Interest cost	1,329	1,554	1,836	603	547	529
Expected return on plan assets	(1,912)	(1,744)	(2,014)	—	—	—
Recognized actuarial loss	979	979	651	395	194	—
Total net periodic expense	$396	$789	$473	$2,092	$1,872	$1,354
Assumptions used to determine net periodic expense:						
Discount rate	2.98%	3.58%	4.50%	3.68%	4.14%	5.15%
Expected return on plan assets	7%	7%	7%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	3.79%	2.98%	3.58%	4.48%	3.68%	4.14%

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, 2014 for the Pension Plans and for the Postretirement Benefits Plan will include expense of $.7 million and $.1 million, respectively, resulting from the amortization of the related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2013.

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, 2013 Postretirement Benefits Plan	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$439	$(328)
Effect on postretirement benefit obligation	2,983	(2,326)

Other Employee Benefit Plans

Forest sponsors various defined contribution plans under which the Company contributed matching contributions equal to $2.7 million in 2013, $3.7 million in 2012, and $3.7 million in 2011.

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 accreted each period to its present value. The Company's estimate of costs expected to be paid in 2014 to maintain these life insurance policies is $1.0 million. Forest recognized accretion expense related to the split dollar life insurance obligations of $1.1 million, $.9 million, and $1.0 million for the years ended December 31, 2013, 2012, and 2011, respectively. The split dollar life insurance obligation recognized in the Consolidated Balance Sheets was $7.3 million as of December 31, 2013 and 2012. The discount rates used to determine the obligations were 3.44% and 2.57% as of December 31, 2013 and 2012, respectively. The cash surrender value of the split dollar life insurance policies recognized in the Consolidated Balance Sheets was $6.5 million and $3.6 million as of December 31, 2013 and 2012, respectively.

(8) FAIR VALUE MEASUREMENTS:

Forest's assets and liabilities measured at fair value on a recurring basis at December 31, 2013 and 2012 are set forth in the table below.

	December 31,	
	2013	2012
	Using Significant Other Observable Inputs (Level 2)[1]	
	(In Thousands)	

Assets:		
Derivative instruments:[2]		
Commodity	$5,592	$35,465
Interest rate	—	13,060
Total Assets	$5,592	$48,525
Liabilities:		
Derivative instruments:[2]		
Commodity	$4,542	$16,551
Total Liabilities	$4,542	$16,551

(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. There were no transfers between levels of the fair value hierarchy during 2013. Forest'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) Forest's currently outstanding derivative assets and liabilities are commodity price derivatives (see Note 9 for more information on these instruments). Forest 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, Forest's derivative instruments are included within the Level 2 fair value hierarchy.

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

	December 31, 2013			
			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	$5,592	$5,592	$—	$5,592
Liabilities:				
Derivative instruments	4,542	4,542	—	4,542
7¼% senior notes due 2019	578,092	568,147	568,147	—
7½% senior notes due 2020	222,087	224,030	224,030	—

(1) Forest 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 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, 2012			
	Carrying Amount	Total Fair Value[1]	Fair Value Measurements 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) Forest 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 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 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 line item "Realized and unrealized losses (gains) on derivative instruments, net" in the Consolidated Statement of Operations.

The table below sets forth Forest's outstanding commodity swaps as of December 31, 2013.

Commodity Swaps

	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
Swap Term	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
Calendar 2014	70	$4.38	3,500	$95.34
Calendar 2015	20	4.20	—	—

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In connection with several natural gas and oil swaps entered into, Forest granted option instruments (several swaptions and puts) to the swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas and oil swaps. Under the terms of the swaption agreements, the counterparties have the option to enter into future swaps with Forest. The swaptions may not be exercised until their expiration dates. Under the terms of the put agreements, the counterparties have the option to put specified quantities of oil to Forest at specified prices. The puts may be exercised monthly by the counterparties. The table below sets forth the outstanding commodity options as of December 31, 2013.

Commodity Options

		Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
Underlying Term	Option Expiration	Underlying Bbtu Per Day	Underlying Hedged Price per MMBtu	Underlying Barrels Per Day	Underlying Hedged Price per Bbl
Gas Swaptions:					
Calendar 2016	December 2014	10	$4.18	—	$—
Oil Swaptions:					
Calendar 2015	December 2014	—	—	3,000	100.00
Calendar 2015	December 2014	—	—	1,000	106.00
Calendar 2015	December 2014	—	—	1,000	99.75
Calendar 2015	December 2014	—	—	1,000	99.00
Oil Put Options:					
Monthly Calendar 2014	Monthly Calendar 2014	—	—	2,000	70.00

Derivative Instruments Entered Into Subsequent to December 31, 2013

Subsequent to December 31, 2013, through February 19, 2014, Forest entered into the following derivative instruments:

Commodity Collars

	Natural Gas (NYMEX HH)		
Collar Term	Bbtu Per Day	Hedged Price per MMBtu	
January 2015 - March 2015	20	$ 4.50/5.31	(1)

(1) Represents the hedged floor and ceiling price per MMBtu.

Interest Rate Derivatives

Forest voluntarily terminated its interest rate swaps in June 2013 for proceeds of $11.4 million, which are included as realized gains in the line item “Realized and unrealized losses (gains) on derivative instruments, net” in the Consolidated Statement of Operations for the year ended December 31, 2013. The original maturity date of the interest rate swaps was February 2014.

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 "Credit Risk" below for more information regarding Forest's master netting arrangements and gross and net presentation of derivative instruments. See also Note 8 for more information on the fair values of Forest's derivative instruments.

	December 31,	
	2013	2012
	(In Thousands)	
Current assets:		
Derivative instruments:		
Commodity	$5,192	$28,690
Interest rate	—	11,500
Total current assets	$5,192	$40,190
Long-term assets:		
Derivative instruments:		
Commodity	$400	$6,775
Interest rate	—	1,560
Total long-term assets	$400	$8,335
Current liabilities:		
Derivative instruments:		
Commodity	$4,542	$9,347
Long-term liabilities:		
Derivative instruments:		
Commodity	$—	$7,204

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. Realized gains and losses represent cash settlements on derivative instruments and unrealized gains and losses represent changes in fair value of derivative instruments. These derivative instruments are not designated as hedging instruments for accounting purposes.

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Commodity derivatives:			
Realized gains	$(14,252)	$(100,420)	$(37,535)
Unrealized losses (gains)	17,863	31,630	(37,542)
Interest rate derivatives:			
Realized gains	(12,885)	(11,352)	(11,442)
Unrealized losses (gains)	13,060	7,496	(1,545)
Realized and unrealized losses (gains) on derivative instruments, net	$3,786	$(72,646)	$(88,064)

Due to the volatility of oil and natural gas 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 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 transacted. As of December 31, 2013, 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 events, 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 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 $4.5 million at December 31, 2013. 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, 2013, Forest owed a net derivative liability to its counterparties, the fair value of which was $3.5 million. In the absence of netting provisions, at December 31, 2013, Forest would be exposed to a risk of loss of $5.6 million under its derivative agreements, and Forest's derivative counterparties would be exposed to a risk of loss of $4.5 million.

For financial reporting purposes, Forest has elected to not offset asset and liability fair value amounts recognized for derivative instruments with the same counterparty under its master netting arrangements, although such derivative instruments are subject to enforceable master netting arrangements. The following tables disclose information regarding the potential effect of netting arrangements on Forest's Consolidated Balance Sheets as of the dates indicated.

	Derivative Assets	
	December 31, 2013	December 31, 2012
	(In Thousands)	
Gross amounts of recognized assets	$5,592	$48,525
Gross amounts offset in the balance sheet	—	—
Net amounts of assets presented in the balance sheet	5,592	48,525
Gross amounts not offset in the balance sheet:		
Derivative instruments	(1,049)	(13,537)
Cash collateral received	—	—
Net amount	$4,543	$34,988

	Derivative Liabilities	
	December 31, 2013	December 31, 2012
	(In Thousands)	
Gross amounts of recognized liabilities	$4,542	$16,551
Gross amounts offset in the balance sheet	—	—
Net amounts of liabilities presented in the balance sheet	4,542	16,551
Gross amounts not offset in the balance sheet:		
Derivative instruments	(1,049)	(13,537)
Cash collateral pledged	—	—
Net amount	$3,493	$3,014

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted, which included derivatives reform as part of a broader financial regulatory reform. Congress delegated many of the details of the Dodd-Frank Act to federal regulatory agencies. Forest currently expects that the Dodd-Frank Act and related rules will have little impact on its existing derivative transactions under its outstanding ISDA Master Agreements and Schedules. However, the legislation could have a substantial impact on Forest's counterparties and increase the cost of Forest's derivative agreements in the future.

(10) COMMITMENTS AND CONTINGENCIES:

The table below sets forth Forest's future payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2013.

	2014	2015	2016	2017	2018	After 2018	Total
	(In Thousands)						
Operating leases[1]	$22,655	$15,823	$15,190	$8,174	$2,083	$7,873	$71,798
Unconditional purchase obligations[2]	5,840	5,805	5,700	—	—	—	17,345
	$28,495	$21,628	$20,890	$8,174	$2,083	$7,873	$89,143

(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. In January 2014, Forest terminated certain drilling rig operating leases for a net loss of approximately $5.0 million, which will reduce the operating lease obligations shown in the table above by $12.4 million in 2014, $10.8 million in 2015, $10.8 million in 2016, and $6.1 million in 2017.

(2) Includes unconditional purchase obligations for drilling commitments and voice and data services. Payments made under these unconditional purchase obligations were $5.8 million in 2013, $.4 million in 2012, and $.4 million in 2011.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and natural gas properties approximated $10.4 million in 2013, $15.6 million in 2012, and $21.0 million in 2011. Net rental payments under non-cancelable operating leases, including drilling rigs and compressor rentals, charged to expense approximated $24.5 million in 2013, $22.0 million in 2012, and $16.5 million in 2011. Forest 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.

(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,		
	2013	2012	2011
	(In Thousands)		
Gain on asset dispositions, net	$(202,023)	$—	$—
Loss on debt extinguishment, net	48,725	36,312	—
Legal proceeding liabilities	—	29,251	6,500
Accretion of asset retirement obligations	2,982	6,663	6,082
Other, net	7,710	11,180	4,582
	$(142,606)	$83,406	$17,164

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Gain on Asset Dispositions, Net

Forest recognized a $193.0 million net gain on its Panhandle divestiture and a $9.0 million net gain on the disposition of its Block 2C Exploration Right in South Africa. See Note 2 for more information regarding Forest's asset divestitures.

Loss on Debt Extinguishment, Net

In November 2013, Forest redeemed $422.1 million in principal amount of 7¼% senior notes at 102.77% of par, recognizing a net loss of $14.7 million upon redemption due to the $11.7 million early tender premium and write-off of $3.0 million of unamortized debt issue costs and premium, net. Also in November 2013, Forest redeemed $277.9 million in principal amount of 7½% senior notes at 101.50% of par, recognizing a loss of $8.8 million upon redemption due to the $4.2 million early tender premium and write-off of $4.6 million of unamortized debt issue costs.

In March 2013, Forest redeemed $300.0 million in principal amount of 8½% senior notes at 107.11% of par, recognizing a loss of $25.2 million upon redemption due to the $21.3 million call premium and write-off of $3.9 million of unamortized debt issue costs and discount.

In October 2012, Forest redeemed $300.0 million in principal amount of 8½% senior 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 debt issue costs and discount.

Legal Proceeding Liabilities

Legal proceeding liabilities for the year ended December 31, 2012 includes $22.8 million for the previously-disclosed arbitration award against Forest in Forest Oil Corp., et al. v. El Rucio Land & Cattle Co., et al. Forest is seeking to have this award 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 $24.2 million, which includes accrued interest, for this matter. Also included in legal proceeding liabilities for the year ended December 31, 2012 is a $7.0 million settlement payment that Forest paid to the plaintiff in exchange for the plaintiff releasing Forest from all claims, indemnifying Forest with respect to all decommissioning and abandonment liabilities associated with Trading Bay, and dismissing the complaint in the previously-disclosed matter Union Oil Company of California v. Forest Oil Corporation.

Legal proceeding liabilities for the year ended December 31, 2011 consists of a $6.5 million settlement payment that Forest paid to the plaintiffs in exchange for the plaintiffs releasing Forest from all claims and dismissing the complaint against Forest in the previously-disclosed matter involving the Alaska assets that Forest sold to Pacific Energy Resources Ltd.

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.

(12) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2013				
Oil, natural gas, and natural gas liquids sales	$118,042	$116,786	$118,028	$88,485
Costs and expenses associated directly with products sold[1]	$75,482	$69,514	$69,881	$57,299
Earnings (loss) before income taxes[2]	$(67,611)	$33,227	$1,627	$105,974
Net earnings (loss)[2]	$(67,948)	$33,439	$2,214	$106,219
Basic and diluted earnings (loss) per share	$(.59)	$.28	$.02	$.89
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 and diluted earnings (loss) per share	$(.29)	$(4.44)	$(3.97)	$(2.48)

(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 and net earnings (loss) have been impacted by non-cash ceiling test write-downs in every quarter of 2012 and the fourth quarter of 2013, 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. Also impacting the fourth quarter of 2013 is a $193.0 million net gain on the Panhandle divestiture, as discussed in Note 2.

(13) DISCONTINUED OPERATIONS:

Lone Pine was a component of Forest, representing Forest's entire Canadian cost center, 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 did 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 Statement of Operations for the year ended December 31, 2011. For more information regarding the spin-off see Note 5.

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

	Nine Months Ended September 30, 2011
	(In Thousands)
Total revenues	$137,834
Production expenses	40,350
General and administrative	8,846
Depreciation, depletion, and amortization	60,780
Interest expense	3,866
Realized and unrealized gains on derivative instruments, net	(33,628)
Realized foreign currency exchange gains	(33,869)
Unrealized foreign currency exchange losses, net	28,488
Other, net	1,328
Earnings from discontinued operations before tax	61,673
Income tax expense	17,104
Net earnings from discontinued operations	$44,569

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited):

Supplemental unaudited information regarding Forest's oil and gas producing activities is presented in this Note. This supplemental information excludes amounts for all periods presented related to Forest's discontinued operations.

Estimated Proved Reserves

Proved reserves are those quantities of oil, natural gas liquids, and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government 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 for oil, natural gas liquids, and natural gas 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. Prices do not include the effects of commodity derivatives. Existing economic conditions include year-end cost estimates.

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

Proved undeveloped reserves are 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.

The following table sets forth the Company's estimates of its net proved, net proved developed, and net proved undeveloped oil, natural gas liquids, and natural gas reserves as of December 31, 2013, 2012, and 2011 and changes in its net proved reserves for the years then ended. For the years presented, the Company engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services.

	Oil (MBbls)			Natural Gas Liquids (MBbls)			Natural Gas (MMcf)				
	United States	Italy	Total	United States	Italy	Total	United States	Italy	Total	Total MMcfe[1]	Total MBoe[1]
Balance at January 1, 2011	20,318	—	20,318	43,384	—	43,384	1,433,731	51,738	1,485,469	1,867,681	311,280
Revisions of previous estimates	(1,061)	—	(1,061)	(3,716)	—	(3,716)	(91,721)	—	(91,721)	(120,383)	(20,064)
Extensions and discoveries	17,816	—	17,816	8,262	—	8,262	144,094	—	144,094	300,562	50,094
Production	(2,491)	—	(2,491)	(3,154)	—	(3,154)	(88,497)	—	(88,497)	(122,367)	(20,395)
Sales of reserves in place	(2,989)	—	(2,989)	(347)	—	(347)	(1,091)	—	(1,091)	(21,107)	(3,518)
Purchases of reserves in place	—	—	—	—	—	—	—	—	—	—	—
Balance at December 31, 2011	31,593	—	31,593	44,429	—	44,429	1,396,516	51,738	1,448,254	1,904,386	317,398
Revisions of previous estimates	(6,151)	—	(6,151)	(6,023)	—	(6,023)	(479,009)	(51,738)	(530,747)	(603,791)	(100,632)
Extensions and discoveries	16,574	—	16,574	6,929	—	6,929	93,643	—	93,643	234,661	39,110
Production	(3,146)	—	(3,146)	(3,489)	—	(3,489)	(81,008)	—	(81,008)	(120,818)	(20,136)
Sales of reserves in place	(5,168)	—	(5,168)	(591)	—	(591)	(17,309)	—	(17,309)	(51,863)	(8,644)
Purchases of reserves in place	—	—	—	—	—	—	—	—	—	—	—
Balance at December 31, 2012	33,702	—	33,702	41,255	—	41,255	912,833	—	912,833	1,362,575	227,096
Revisions of previous estimates	(3,394)	—	(3,394)	(1,973)	—	(1,973)	22,032	—	22,032	(10,170)	(1,695)
Extensions and discoveries	11,617	—	11,617	4,602	—	4,602	51,105	—	51,105	148,419	24,737
Production	(2,271)	—	(2,271)	(2,521)	—	(2,521)	(46,676)	—	(46,676)	(75,428)	(12,571)
Sales of reserves in place	(22,980)	—	(22,980)	(29,652)	—	(29,652)	(484,703)	—	(484,703)	(800,495)	(133,416)
Purchases of reserves in place	—	—	—	—	—	—	—	—	—	—	—
Balance at December 31,	16,674	—	16,674	11,711	—	11,711	454,591	—	454,591	624,901	104,150

2013										
Proved developed reserves at:										
January 1, 2011	13,421	—	13,421	24,120	—	24,120	886,644	25,869	912,513	1,137,759	189,627
December 31, 2011	14,149	—	14,149	23,170	—	23,170	814,160	—	814,160	1,038,074	173,012
December 31, 2012	12,315	—	12,315	25,518	—	25,518	710,288	—	710,288	937,286	156,214
December 31, 2013	6,151	—	6,151	6,855	—	6,855	336,342	—	336,342	414,378	69,063
Proved undeveloped reserves at:										
January 1, 2011	6,897	—	6,897	19,264	—	19,264	547,087	25,869	572,956	729,922	121,654
December 31, 2011	17,444	—	17,444	21,259	—	21,259	582,356	51,738	634,094	866,312	144,385
December 31, 2012	21,387	—	21,387	15,737	—	15,737	202,545	—	202,545	425,289	70,882
December 31, 2013	10,523	—	10,523	4,856	—	4,856	118,249	—	118,249	210,523	35,087

(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. Likewise, natural gas is converted to oil-equivalents using a conversion of one barrel of oil "equivalent" per six Mcf of natural gas. These conversions are based on energy equivalence and not price equivalence.

Revisions of Previous Estimates

In 2013, net negative revisions of 10 Bcfe were comprised of (i) the reclassification of 41 Bcfe of proved undeveloped reserves ("PUDs") to probable undeveloped reserves for PUDs that are not expected to be developed five years from the time the reserves were initially disclosed, (ii) negative performance revisions of 9 Bcfe, and positive pricing revisions of 40 Bcfe due primarily to the increase in price of natural gas used in calculating proved reserves. In 2012, net negative revisions of 604 Bcfe 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 the reserve estimates. In addition, lower natural gas prices also delayed Forest's initial expected development time frame for drilling certain of its proved undeveloped natural gas locations beyond five years from the time the associated reserves were originally recorded. Accordingly, these PUDs were reclassified to probable undeveloped reserves in 2012. Additionally, all 52 Bcfe of the Company's Italian PUDs were reclassified to probable due to an Italian regional regulatory body's 2012 denial of the Company's environmental impact assessment associated with the Company's proposal to commence natural gas production from wells that it drilled and completed in 2007. The Company is currently appealing the region's denial; however, until the region's denial is reversed or overturned, the Company determined that it could no longer conclude with reasonable certainty that its Italian natural gas reserves are producible. In 2011, the net negative revisions of 120 Bcfe were primarily the result of the write-off of PUDs pursuant to the five year limitation and the write-off of natural gas reserves associated with a deep gas project in South Louisiana.

Extensions and Discoveries

In 2013, the Company had 148 Bcfe of extensions and discoveries, which were primarily due to exploration and development activities in the Eagle Ford in South Texas and Cotton Valley in East Texas. In 2012, the Company had 235 Bcfe of extensions and discoveries, which were primarily due to exploration and development activities in the Texas Panhandle and Eagle Ford in South Texas. In 2011, the Company had 301 Bcfe of extensions and discoveries, which were also primarily due to exploration and development activities in the Texas Panhandle and Eagle Ford in South Texas.

Sales of Reserves in Place

Sales of reserves in place for each of the years presented in the table above represent the sale of oil and natural gas property interests. See Note 2 for a description of these asset divestitures.

Aggregate Capitalized Costs

The aggregate capitalized costs relating to oil and gas producing activities were as follows as of the dates indicated:

	December 31, 2013	2012
	(In Thousands)	
Costs related to proved properties	$9,213,668	$9,696,498
Costs related to unproved properties	53,645	277,798
	9,267,313	9,974,296
Less accumulated depletion[(1)]	(8,460,589)	(8,237,186)
	$806,724	$1,737,110

(1) Includes inception-to-date ceiling test write-downs.

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

The following costs were incurred in oil and gas property acquisition, exploration, and development activities during the years ended December 31, 2013, 2012, and 2011:

	United States	Italy	Total
	(In Thousands)		
2013			
Property acquisition costs:			
Proved properties	$—	$—	$—
Unproved properties	7,117	—	7,117
Exploration costs	129,946	—	129,946
Development costs	213,127	—	213,127
Total costs incurred[(1)]	$350,190	$—	$350,190
2012			
Property acquisition costs:			
Proved properties	$—	$—	$—
Unproved properties	64,123	—	64,123
Exploration costs	268,153	700	268,853
Development costs	398,941	182	399,123
Total costs incurred[(1)]	$731,217	$882	$732,099
2011			
Property acquisition costs:			
Proved properties	$—	$—	$—
Unproved properties	204,484	—	204,484
Exploration costs	286,412	1,003	287,415
Development costs	417,469	366	417,835
Total costs incurred[(1)]	$908,365	$1,369	$909,734

(1) Includes amounts relating to changes in estimated asset retirement obligations of $8.6 million, $6.1 million, and $3.1 million recorded during the years ended December 31, 2013, 2012, and 2011, respectively.

Results of Operations from Oil and Gas Producing Activities

Results of operations from oil and gas producing activities for the years ended December 31, 2013, 2012, and 2011 are presented below.

	United States	Italy	Total
	(In Thousands, except per Mcfe amounts)		
2013			
Oil, natural gas, and natural gas liquids sales	$441,341	$—	$441,341
Expenses:			
Production expense	103,427	—	103,427
Depletion expense	165,767	—	165,767
Ceiling test write-down of oil and natural gas properties	57,636	—	57,636
Accretion of asset retirement obligations	2,760	74	2,834
Income tax benefit	(707)	—	(707)
Total expenses	328,883	74	328,957
Results of operations from oil and gas producing activities	$112,458	$(74)	$112,384
Depletion rate per Mcfe	$2.20	$—	$2.20
2012			
Oil, natural gas, and natural gas liquids sales	$605,523	$—	$605,523
Expenses:			
Production expense	156,909	—	156,909
Depletion expense	275,886	—	275,886
Ceiling test write-down of oil and natural gas properties	957,587	34,817	992,404
Accretion of asset retirement obligations	6,487	62	6,549
Income tax expense	173,437	—	173,437
Total expenses	1,570,306	34,879	1,605,185
Results of operations from oil and gas producing activities	$(964,783)	$(34,879)	$(999,662)
Depletion rate per Mcfe	$2.28	$—	$2.28
2011			
Oil, natural gas, and natural gas liquids sales	$703,531	$—	$703,531
Expenses:			
Production expense	153,518	—	153,518
Depletion expense	213,866	—	213,866
Accretion of asset retirement obligations	5,973	44	6,017
Income tax expense	89,135	—	89,135
Total expenses	462,492	44	462,536
Results of operations from oil and gas producing activities	$241,039	$(44)	$240,995
Depletion rate per Mcfe	$1.75	$—	$1.75

Standardized Measure of Discounted Future Net Cash Flows

Future oil, natural gas, and NGL sales are calculated applying the prices used in estimating the Company’s proved oil, natural gas, and NGL reserves to the year-end quantities of those reserves. Future price changes were considered only to the extent provided by contractual arrangements in existence at each year-end. Future production

and development costs, which include costs related to plugging of wells, removal of facilities and equipment, and site restoration, are calculated by estimating the expenditures to be incurred in producing and developing the proved reserves at the end of each year, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax deductions, credits, and allowances relating to the proved reserves. All cash flow amounts, including income taxes, are discounted at 10%.

Changes in the demand for oil, natural gas, and NGLs, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of the Company's proved reserves. Management does not rely upon the information that follows in making investment decisions.

	December 31, 2013		
	United States	Italy	Total
	(In Thousands)		
Future oil, natural gas, and natural gas liquids sales	$3,459,749	$—	$3,459,749
Future production costs	(1,165,344)	—	(1,165,344)
Future development costs	(676,684)	—	(676,684)
Future income taxes	(18,441)	—	(18,441)
Future net cash flows	1,599,280	—	1,599,280
10% annual discount for estimated timing of cash flows	(864,672)	—	(864,672)
Standardized measure of discounted future net cash flows	$734,608	$—	$734,608

	December 31, 2012		
	United States	Italy	Total
	(In Thousands)		
Future oil, natural gas, and natural gas liquids sales	$6,929,652	$—	$6,929,652
Future production costs	(2,166,681)	—	(2,166,681)
Future development costs	(1,444,144)	—	(1,444,144)
Future income taxes	(142,383)	—	(142,383)
Future net cash flows	3,176,444	—	3,176,444
10% annual discount for estimated timing of cash flows	(1,779,347)	—	(1,779,347)
Standardized measure of discounted future net cash flows	$1,397,097	$—	$1,397,097

	December 31, 2011		
	United States	Italy	Total
	(In Thousands)		
Future oil, natural gas, and natural gas liquids sales	$10,427,716	$576,364	$11,004,080
Future production costs	(2,692,993)	(199,054)	(2,892,047)
Future development costs	(2,008,824)	(18,692)	(2,027,516)
Future income taxes	(940,526)	(130,836)	(1,071,362)
Future net cash flows	4,785,373	227,782	5,013,155
10% annual discount for estimated timing of cash flows	(2,499,631)	(125,783)	(2,625,414)
Standardized measure of discounted future net cash flows	$2,285,742	$101,999	$2,387,741

Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

An analysis of the changes in the standardized measure of discounted future net cash flows during each of the last three years is as follows:

	December 31, 2013 United States (In Thousands)
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at beginning of year	$1,397,097
Changes resulting from:	
Sales of oil, natural gas, and NGL net of production costs	(337,914)
Net changes in prices and future production costs	222,516
Net changes in future development costs	50,568
Extensions, discoveries, and improved recovery	295,585
Development costs incurred during the period	128,482
Revisions of previous quantity estimates	(114,712)
Changes in production rates, timing, and other	19,321
Sales of reserves in place	(1,099,372)
Purchases of reserves in place	—
Accretion of discount on reserves at beginning of year	143,432
Net change in income taxes	29,605
Total change for year	(662,489)
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at end of year	$734,608

The computation of the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2013 was based on average prices and year-end costs. The Henry Hub average natural gas price and West Texas Intermediate average oil price during the twelve-month period prior to December 31, 2013 were $3.67 per MMBtu and $97.33 per barrel, respectively.

	December 31, 2012		
	United States	Italy	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at beginning of year	$2,285,742	$101,999	$2,387,741
Changes resulting from:			
Sales of oil, natural gas, and NGL net of production costs	(448,614)	—	(448,614)
Net changes in prices and future production costs	(1,226,494)	(9,264)	(1,235,758)
Net changes in future development costs	(4,188)	—	(4,188)
Extensions, discoveries, and improved recovery	572,516	—	572,516
Development costs incurred during the period	140,111	—	140,111
Revisions of previous quantity estimates	(203,987)	(151,578)	(355,565)
Changes in production rates, timing, and other	(34,665)	—	(34,665)
Sales of reserves in place	(213,683)	—	(213,683)
Purchases of reserves in place	—	—	—
Accretion of discount on reserves at beginning of year	259,393	3,923	263,316
Net change in income taxes	270,966	54,920	325,886
Total change for year	(888,645)	(101,999)	(990,644)
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at end of year	$1,397,097	$—	$1,397,097

The computation of the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2012 was based on average prices and year-end costs. The Henry Hub average natural gas price and West Texas Intermediate average oil price during the twelve-month period prior to December 31, 2012 were $2.76 per MMBtu and $94.79 per barrel, respectively.

	December 31, 2011		
	United States	Italy	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at beginning of year	$1,964,920	$205,526	$2,170,446
Changes resulting from:			
Sales of oil, natural gas, and NGL net of production costs	(550,013)	—	(550,013)
Net changes in prices and future production costs	272,027	(153,313)	118,714
Net changes in future development costs	(55,725)	(697)	(56,422)
Extensions, discoveries, and improved recovery	667,323	—	667,323
Development costs incurred during the period	231,270	—	231,270
Revisions of previous quantity estimates	(220,389)	—	(220,389)
Changes in production rates, timing, and other	(132,714)	(40,508)	(173,222)
Sales of reserves in place	(107,742)	—	(107,742)
Purchases of reserves in place	—	—	—
Accretion of discount on reserves at beginning of year	226,354	31,949	258,303
Net change in income taxes	(9,569)	59,042	49,473
Total change for year	320,822	(103,527)	217,295
Standardized measure of discounted future net cash flows relating to proved oil, natural gas, and NGL reserves, at end of year	$2,285,742	$101,999	$2,387,741

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The computation of the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2011 was based on average prices and year-end costs. The Henry Hub average natural gas price and West Texas Intermediate average oil price during the twelve-month period prior to December 31, 2011 were $4.12 per MMBtu and $96.08 per barrel, respectively.

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures.

We have established disclosure controls and procedures to ensure that material information relating to Forest and its consolidated subsidiaries is made known to the Officers who certify Forest's financial reports and the Board of Directors.

Our Chief Executive Officer, Patrick R. McDonald, and our Chief Financial Officer, Victor A. Wind, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of the end of the period covered by this Annual Report on Form 10-K (the "Evaluation Date"). Based on this evaluation, they believe that as of the Evaluation Date our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (i) is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms; and (ii) is accumulated and communicated to Forest's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework). Based on our evaluation under the framework in Internal Control—Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2013. The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control Over Financial Reporting.

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Forest Oil Corporation

We have audited Forest Oil Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Forest Oil Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Forest Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Forest Oil Corporation as of December 31, 2013 and 2012 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, 2013 and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 26, 2014

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PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The following persons were serving as executive officers of Forest as of February 19, 2014.

Name	Age	Years with Forest	Office[1]
Patrick R. McDonald	56	2	President and Chief Executive Officer since September 2012 after serving as our Interim Chief Executive Officer since June 2012, and has been a member of the Board since 2004. He was appointed as the Chief Executive Officer and as a Director of Carbon Natural Gas Co. in 2011, and continues to serve in such capacities. He also served as Chief Executive Officer, President, and Director of Carbon Natural Gas Co.'s predecessor company, Nytis Exploration Company, since 2004. From 1998 to 2003, Mr. McDonald served as President, Chief Executive Officer, and Director of Carbon Energy Corporation, an oil and gas exploration and production company. From 1987 to 1997, Mr. McDonald served as Chief Executive Officer, President, and Director of Interenergy Corporation, a natural gas gathering, processing, and marketing company. Prior to that he worked as an exploration geologist with Texaco, Inc. where he was responsible for oil and gas exploration efforts in the Middle and Far East. In March 2011, Mr. McDonald was elected as a director of Lone Pine Resources Inc., an oil and gas exploration, development, and production company.
Victor A. Wind	40	9	Executive Vice President and Chief Financial Officer since November 2013; Executive Vice President, Chief Financial Officer, and Treasurer from August 2013 until November 2013; Senior Vice President, Chief Accounting Officer, Corporate Controller, and Treasurer since January 2013 until August 2013; Senior Vice President, Chief Accounting Officer, and Corporate Controller from December 2009 until January 2013; Vice President, Chief Accounting Officer, and Corporate Controller from May until December 2009. Mr. Wind joined Forest in January 2005 as our Corporate Controller. Mr. Wind was previously employed by Evergreen Resources, Inc. from July 2001 to December 2004. He served in various management positions during this period, including Director of Financial Reporting and Controller. From 1997 to 2001, he served in various capacities at BDO Seidman, LLP.
Larry C. Busnardo	45	2	Vice President, Investor Relations since November 2013. Mr. Busnardo joined Forest in April 2012 as Director, Investor Relations. Prior to joining Forest, Mr. Busnardo was with Macquarie Capital (USA) from September 2009 until March 2012, where he served as both an equity research analyst covering the small-cap exploration and production sector and in an energy specialty sales capacity. He served in a similar capacity with Tristone Capital (USA) from February 2007 until its acquisition by Macquarie in September 2009. Prior to that, Mr. Busnardo had 15 years of experience as an equity research analyst and in various investor relations and finance positions working in the exploration and production industry.

Frederick B. Dearman II	56	4	Senior Vice President, Southern Region since August 2012. Mr. Dearman joined Forest in August 2010 as Managing Director, New Ventures, a role he filled until October 2011, when he was promoted to Vice President of that business unit. Prior to joining Forest, Mr. Dearman served as Special Projects Manager at Apache Corporation, an oil and gas company, from 2001 to 2010. He also held the positions of Corporate Reservoir Engineering Manager from 1998 to 2001 and Senior Staff Reservoir Engineer from 1996 to 1997 at Apache Corporation. He was employed by Amerada Hess Corporation, also an oil and gas company, as a petroleum engineer from 1987 to 1996.
Michael J. Dern	59	13	Senior Vice President, Corporate Engineering and Technology, since January 2013. Mr. Dern served as Forest's Vice President, Corporate Engineering, from July 2011 until January 2013, as Manager, Reservoir Engineering, Eastern Region, from May 2005 until July 2011, and as Manager, Corporate Planning, from May 2001 until May 2005. Prior to joining Forest, he had more than 20 years of industry experience in corporate planning, reservoir engineering, and reservoir engineering management at Phillips Petroleum, Exeter Exploration, Midcon Exploration, Apache Corporation, and Gulf Canada Resources.
Timothy F. Savoy	54	12	Senior Vice President, Mid-Continent Region since December 2013. Mr. Savoy joined Forest in February 2002 as Director Health, Safety, and Environment. In June 2004, he became Vice President, Operations Support and served in that capacity until November 2013, when he was promoted to Senior Vice President, Mid-Continent Region. Mr. Savoy was previously employed by Apache Corporation, an oil and gas exploration and production company, from 1991 to 2001, where he served in various capacities. From 1983 to 1991 he served in various engineering positions at Amoco Production Company.
Richard W. Schelin	68	36	Vice President, General Counsel, and Secretary since January 2014. Mr. Schelin previously served as Forest's Deputy General Counsel from October 2000 until his appointment as General Counsel. Prior to joining Forest's legal department in February 1978, Mr. Schelin was an attorney at the law firm of Moyers, Martin, Conway, Santee & Imel in Tulsa, Oklahoma.

(1) Officers are appointed annually at the Board meeting immediately following the annual shareholder meeting, to serve for one-year terms, or until their death, resignation, or removal from office, whichever first occurs.

The following information will be included in Forest's Notice of Annual Meeting of Shareholders and Proxy Statement (the "Proxy Statement") to be filed with the SEC within 120 days after Forest's fiscal year end of December 31, 2013 and is incorporated herein by reference:

- Information concerning Forest's directors is incorporated by reference to the information under the caption "Proposal No. 1—Election of Directors"

- Information concerning the procedures for shareholders of Forest to recommend nominees to the Board is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Consideration of Director Nominees—Shareholder Nominees"

- Information concerning Forest's Audit Committee and designated "audit committee financial expert" is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Board Structure; Committee Composition; Meetings"

- Information about Forest's code of ethics for directors, officers, and employees is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Corporate Governance Guidelines and Code of Business Ethics"

- Information about compliance with Section 16(a) of the Exchange Act is set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance"

Item 11. Executive Compensation.

Information regarding Forest's compensation of its named executive officers and directors is set forth under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference. See also "Executive Compensation—Compensation Committee Report" and "Corporate Governance Principles and Information about the Board and its Committees—Compensation Committee Interlocks and Insider Participation" for additional information, which information is incorporated herein by reference.

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

Information regarding security ownership of certain beneficial owners, directors, and executive officers is set forth under the caption "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement, which information is incorporated herein by reference.

Information regarding Forest's equity compensation plans is set forth under the caption "Equity Compensation Plan Information" in the Proxy Statement, which information is incorporated herein by reference.

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

Information regarding certain relationships and related transactions is set forth under the caption "Transactions with Related Persons, Promoters and Certain Control Persons," and information regarding director independence is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Board Independence" in the Proxy Statement, which information is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

Information regarding principal accounting fees and services is set forth under the caption "Principal Accountant Fees and Services" in the Proxy Statement, which information is incorporated herein by reference.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

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

(1) Financial Statements:

1. Report of Independent Registered Public Accounting Firm

2. Consolidated Balance Sheets—December 31, 2013 and 2012

3. Consolidated Statements of Operations—Years Ended December 31, 2013, 2012, and 2011

4. Consolidated Statements of Comprehensive Income—Years Ended December 31, 2013, 2012, and 2011

5. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2013, 2012, and 2011

6. Consolidated Statements of Cash Flows—Years Ended December 31, 2013, 2012, and 2011

7. Notes to Consolidated Financial Statements—Years Ended December 31, 2013, 2012, and 2011

(2) Financial Statement Schedules: All schedules have been omitted because the information is either not required or is set forth in the financial statements or the notes thereto.

(3) Exhibits: See the Index of Exhibits in Item 15(b) hereof for a list of those exhibits filed as part of this Annual Report on Form 10-K.

(b) Index of Exhibits:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Forest Oil Corporation, as amended to date, incorporated herein by reference to Exhibit 3.2 to Form 8-K for Forest Oil Corporation filed October 12, 2012 (File No. 001-13515).
3.2	Bylaws of Forest Oil Corporation Restated as of February 14, 2001, as amended by Amendments No. 1, No. 2, No. 3, No. 4, No. 5, and No. 6, incorporated herein by reference to Exhibit 3.2 to Registration Statement on Form S-4 for Forest Oil Corporation filed June 4, 2013 (File 333-189064).
4.1	Indenture dated December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.5 to Forest Oil Corporation Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
4.2	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.6 to Forest Oil Corporation Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.3	Indenture dated as of June 6, 2007 between Forest Oil Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.4	Indenture dated as of February 17, 2009 between Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
4.5	Indenture, dated as of September 17, 2012, by and among Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation filed September 17, 2012 (File No. 001-13515).
4.6	First Amended and Restated Rights Agreement, dated as of October 17, 2003, between Forest Oil Corporation and Mellon Investor Services LLC, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation, dated October 17, 2003 (File No. 001-13515).
4.7	Second Amended and Restated Credit Agreement dated as of June 6, 2007 among Forest Oil Corporation, each of the lenders that is party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas, BMO Capital Markets Financing, Inc., Credit Suisse, Cayman Islands Branch, and Deutsche Bank Securities, Inc., as Co-U.S. Documentation Agents, and JPMorgan Chase Bank, N.A., as Global Administrative Agent, incorporated herein by reference to Exhibit 4.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.8	First Amendment dated May 9, 2008 to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders party

	thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank N.A., Toronto Branch, as Canadian Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 9, 2008 (File No. 001-13515).
4.9	Second Amendment dated March 16, 2009, to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation dated March 16, 2009 (File No. 001-13515).

Exhibit Number		Description
4.10		Third Amendment to Second Amended and Restated U.S. Credit Agreement and Termination of Second Amended and Restated Canadian Credit Agreement, dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., JPMorgan Chase Bank, N.A., Toronto branch, as Canadian Administrative Agent, JPMorgan Chase Bank, N.A., as global administrative agent, and the Lenders named therein, incorporated by reference to Exhibit 4.1 to Form 8-K to Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
4.11		Third Amended and Restated Credit Agreement, dated as of June 30, 2011, among Forest Oil Corporation, the Lenders party thereto, BNP Paribas and Wells Fargo Bank, N.A., as Co-Syndication Agents, Bank of America, N.A., The Bank of Nova Scotia, Credit Suisse AG, Cayman Islands branch, Deutsche Bank Securities, Inc. and Toronto Dominion (Texas) LLC, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., as Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed July 6, 2011 (File No. 001-13515).
4.12		First Amendment to Third Amended and Restated Credit Agreement, dated as of September 12, 2013, among Forest Oil Corporation, the lenders signatory thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed September 18, 2013 (File No. 001-13515).
10.1	*	Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 4.1 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.2	*	Amendment No. 1 to Forest Oil Corporation’s 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2003 (File No. 001-13515).
10.3	*	Amendment No. 2 to Forest Oil Corporation’s 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2004 (File No. 001-13515).
10.4	*	Amendment No. 3 to Forest Oil Corporation 2001 Stock Incentive Plan, dated January 10, 2006, incorporated herein by reference to Exhibit 10.8 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.5	*	Amendment No. 4 to Forest Oil Corporation 2001 Stock Incentive Plan dated June 5, 2007, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.6	*	Form of Employee Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.7	*	Form of Non-Employee Director Stock Option Agreement, incorporated herein by reference to Exhibit 4.3 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).

10.8	*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.9	*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.12 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.10	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
10.11	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).

Exhibit Number		Description
10.12	*	Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Annex E to Forest Oil Corporation's Registration Statement on Form S-4, dated April 30, 2007 (File No. 333-140532).
10.13	*	Amendment No. 1 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.14	*	Amendment No. 2 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 12, 2010 (File No. 001-13515).
10.15	*	Amendment No. 3 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2011 (File No. 001-13515).
10.16	*	Amendment No. 4 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.6 to Form 8-K for Forest oil Corporation filed December 21, 2012 (File No. 001-13515).
10.17	*	Amendment No. 5 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 7, 2013 (File No. 001-13515).
10.18	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
10.19	*	Form of Non-Employee Director Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2008 (File No. 001-13515).
10.20	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.21	*	Form of Restricted Stock Inducement Award Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.22	*	Form of CEO Restricted Stock Award Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.23	*	Form of 2013 Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - Cliff Vest, incorporated herein by reference to Exhibit 10.22 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).

10.24	*	Form of 2013 Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - One-Third Vest, incorporated herein by reference to Exhibit 10.23 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.25	*	Form of 2013 Restricted Stock Award Agreement - Cliff Vesting (updated), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.26	*	Form of 2013 Restricted Stock Award Agreement - Annual Vesting (updated), incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).

Exhibit Number		Description
10.27	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.28	*	Form of Non-Employee Director Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.29	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2009 (File No. 001-13515).
10.30	*	Form of Phantom Stock Unit Agreement (Cash Only Three Vesting Tranches) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2011 (File No. 001-13515).
10.31	*	Form of Phantom Stock Unit Agreement (4-Year Pro-Rated Vesting) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed November 14, 2012 (File No. 001-13515).
10.32	*	Form of 2013 Cash Only Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - Cliff Vest, incorporated by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.33	*	Form of 2013 Cash Only Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - One-Third Vest, incorporated by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.34	*	Form of 2013 Phantom Stock Unit Award Agreement - Cliff Vesting (updated), incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.35	*	Form of 2013 Phantom Stock Unit Award Agreement - Annual Vesting (updated), incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.36	*	Form of Performance Unit Award Agreement (US) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.37	*	Form of Forest Oil Corporation Performance Unit Award Agreement - 2012, pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed March 16, 2012 (File No. 001-13515).
10.38	*	Form of CEO Plan Performance Unit Award Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 8-K to Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).

10.39	*	Form of Performance Unit Inducement Award Agreement, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.40	*	Form of 2013 Performance Unit Award Agreement - Stock Settled, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.41	*	Form of 2013 Performance Unit Award Agreement - Cash Settled, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.42	*	Form of Cash-Based Award Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 13, 2011 (File No. 001-13515).

Exhibit Number		Description
10.43	*	Form of Forest Oil Corporation Cash-Based Award Agreement - 2012, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed May 16, 2012 (File No. 001-13515).
10.44	*	Form of Time-Based Cash Award Agreement, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed November 14, 2012 (File No. 001-13515).
10.45	*	Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.46	*	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.47	*	Form of 409A Amendment to Severance Agreement for Grandfathered Vice President and Senior Vice President – No 5-Day Release Provision, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2012 (File No. 001-13515).
10.48	*	Form of CEO Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.49	*	Amendment to CEO Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.50	*	Form of SVP Best Net Severance Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.51	*	Form of SVP Best Net Grandfathered Severance Agreement, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No.001-13515).
10.52	*	Form of VP Best Net Severance Agreement, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.53	*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002, dated November 14, 2002 (File No. 001-13515).
10.54	*	First Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2005, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2005 (File No. 001-13515).
10.55	*	Second Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2006, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation dated August 9, 2006 (File No. 001-13515).
10.56	*	

		Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.41 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.57	*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 9, 2009 (File No. 001-13515).
10.58	*	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated by reference to Exhibit 10.50 to form 10-K for Forest Oil Corporation for the fiscal year ended December 31, 2011 (File No. 001-13515).
10.59	*	Third Amendment to Forest Oil Corporation Executive Deferred Compensation Plan, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).

Exhibit Number		Description
10.60	*	Forest Oil Corporation 2011 Annual Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed August 16, 2011 (File No. 001-13515).
10.61	*	Forest Oil Corporation 2012 Annual Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed January 10, 2012 (File No. 001-13515).
10.62	*	Forest Oil Corporation 2013 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 17, 2013 (File No. 001-13515).
10.63		Separation and Distribution Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.64		Transition Services Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.65		Tax Sharing Agreement dated May 25, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.66		Employee Matters Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.67		Registration Rights Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.68		Registration Rights Agreement, dated as of September 17, 2012, by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P. Morgan Securities LLC, as representative for the Initial Purchasers, incorporated herein by reference to Exhibit 4.2 to Form 8-K for Forest Oil Corporation filed September 17, 2012 (File No. 001-13515).
10.69		Share Purchase and Sale Agreement, effective as of March 31, 2012, by and among African International Energy PLC, Forest Oil Corporation, Anschutz South Africa Corporation, Forest Exploration International (South Africa) (Proprietary) Ltd and Anschutz Overseas (South Africa) (Proprietary) ltd, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed April 13, 2012 (File No. 001-13515).
10.70		Share Purchase and Sale Agreement, effective as of March 31, 2012, by and between African International Energy PLC and Forest Oil Netherlands BV, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed April 13, 2012 (File No. 001-13515).
10.71		Agreement for Purchase and Sale of Assets, dated as of October 11, 2012, by and between Forest Oil Corporation and Texas Petroleum Investment Company, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 12, 2012 (File No. 001.13515).

10.72	Agreement, dated as of October 22, 2012, by and among Forest Oil Corporation, Richard J. Carty, West Face Capital Inc. and West Face Long Term Opportunities Global Market L.P., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 24, 2012 (File No. 001-13515).
10.73	Confidentiality Agreement, dated October 22, 2012, by and between Forest Oil Corporation and West Face Capital Inc., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed October 24, 2012 (File no. 001-13515).
10.74	Agreement for Purchase and Sale of Assets, dated as of January 2, 2012, by and between Forest Oil Corporation, Forest Oil Permian Corporation, and Forcenergy Onshore Inc. (as Seller) and Hilcorp Energy I, L.P. (as Purchaser), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed January 3, 2012 (File No. 001-13515).

Exhibit Number		Description
10.75		Purchase Agreement, dated as of September 12, 2013, by and among Forest Oil Corporation, Forest Oil Permian Corporation and the Initial purchasers named therein, incorporated herein by reference to Exhibit 1.1 to Form 8-K for Forest Oil Corporation filed September 18, 2013 (File No. 001-13515).
10.76		Acquisition and Development Agreement, dated April 11, 2013, by and between Forest Oil Corporation, STC Eagleville, LLC, Schlumberger Technology Corporation, Smith International, Inc., and M-I L.L.C., incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed April 17, 2013 (File No. 001-13515).
10.77		Operating Agreement, dated April 11, 2013, by and between Forest Oil Corporation and STC Eagleville LLC, incorporated by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed April 17, 2013 (File No. 001-13515).
10.78		Agreement for Purchase and Sale of Assets, dated as of October 3, 2013, by and between Forest Oil Corporation, Forest Oil Permian Corporation, and Templar Energy LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 4, 2013 (File No. 001-13515).
21.1	†	List of Subsidiaries of Registrant.
23.1	†	Consent of Ernst & Young LLP.
23.2	†	Consent of DeGolyer and MacNaughton.
24.1	†	Power of Attorney (included on the signature pages hereof).
31.1	†	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2	†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
32.1	**	Certification of Chief Executive Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
32.2	**	Certification of Chief Financial Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
99.1	†	Reserves Audit Report of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 24, 2014.
101.INS	±	XBRL Instance Document.
101.SCH	±	XBRL Taxonomy Extension Schema Document.
101.CAL	±	XBRL Taxonomy Extension Calculation Linkbase Document.

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*Contract or compensatory plan or arrangement in which directors and/or officers participate.
**Not considered to be “filed” for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.
†Indicates Exhibits filed with this Annual Report on Form 10-K.
±The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed as part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, are deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise, are not subject to liability under these sections.

SIGNATURES

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

FOREST OIL CORPORATION
(Registrant)

February 26, 2014

By: /s/ PATRICK R. MCDONALD
Patrick R. McDonald
President and Chief Executive Officer

Power of Attorney

The officers and directors of Forest Oil Corporation, whose signatures appear below, hereby constitute and appoint Patrick R. McDonald, Richard W. Schelin, and Victor A. Wind and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this Annual Report on Form 10-K for the year ended December 31, 2013, and any instrument or document filed as part of, as an exhibit to or in connection with any amendment, and each of the undersigned does hereby ratify and confirm as his own act and deed all that said attorneys shall do or cause to be done by virtue thereof.

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

Signatures	Title	Date
/s/ PATRICK R. MCDONALD Patrick R. McDonald	President and Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2014
/s/ VICTOR A. WIND Victor A. Wind	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 26, 2014
/s/ JAMES D. LIGHTNER James D. Lightner	Chairman of the Board	February 26, 2014
/s/ LOREN K. CARROLL Loren K. Carroll	Director	February 26, 2014
/s/ RICHARD J. CARTY Richard J. Carty	Director	February 26, 2014
/s/ DOD A. FRASER Dod A. Fraser	Director	February 26, 2014
/s/ JAMES H. LEE James H. Lee	Director	February 26, 2014
/s/ RAYMOND I. WILCOX Raymond I. Wilcox	Director	February 26, 2014

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Index to Exhibits

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Forest Oil Corporation, as amended to date, incorporated herein by reference to Exhibit 3.2 to Form 8-K for Forest Oil Corporation filed October 12, 2012 (File No. 001-13515).
3.2	Bylaws of Forest Oil Corporation Restated as of February 14, 2001, as amended by Amendments No. 1, No. 2, No. 3, No. 4, No. 5, and No. 6, incorporated herein by reference to Exhibit 3.2 to Registration Statement on Form S-4 for Forest Oil Corporation filed June 4, 2013 (File 333-189064).
4.1	Indenture dated December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.5 to Forest Oil Corporation Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
4.2	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.6 to Forest Oil Corporation Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.3	Indenture dated as of June 6, 2007 between Forest Oil Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.4	Indenture dated as of February 17, 2009 between Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
4.5	Indenture, dated as of September 17, 2012, by and among Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation filed September 17, 2012 (File No. 001-13515).
4.6	First Amended and Restated Rights Agreement, dated as of October 17, 2003, between Forest Oil Corporation and Mellon Investor Services LLC, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation, dated October 17, 2003 (File No. 001-13515).
4.7	Second Amended and Restated Credit Agreement dated as of June 6, 2007 among Forest Oil Corporation, each of the lenders that is party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas, BMO Capital Markets Financing, Inc., Credit Suisse, Cayman Islands Branch, and Deutsche Bank Securities, Inc., as Co-U.S. Documentation Agents, and JPMorgan Chase Bank, N.A., as Global Administrative Agent, incorporated herein by reference to Exhibit 4.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.8	First Amendment dated May 9, 2008 to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders party

	thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank N.A., Toronto Branch, as Canadian Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 9, 2008 (File No. 001-13515).
4.9	Second Amendment dated March 16, 2009, to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation dated March 16, 2009 (File No. 001-13515).

Exhibit Number		Description
4.10		Third Amendment to Second Amended and Restated U.S. Credit Agreement and Termination of Second Amended and Restated Canadian Credit Agreement, dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., JPMorgan Chase Bank, N.A., Toronto branch, as Canadian Administrative Agent, JPMorgan Chase Bank, N.A., as global administrative agent, and the Lenders named therein, incorporated by reference to Exhibit 4.1 to Form 8-K to Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
4.11		Third Amended and Restated Credit Agreement, dated as of June 30, 2011, among Forest Oil Corporation, the Lenders party thereto, BNP Paribas and Wells Fargo Bank, N.A., as Co-Syndication Agents, Bank of America, N.A., The Bank of Nova Scotia, Credit Suisse AG, Cayman Islands branch, Deutsche Bank Securities, Inc. and Toronto Dominion (Texas) LLC, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., as Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed July 6, 2011 (File No. 001-13515).
4.12		First Amendment to Third Amended and Restated Credit Agreement, dated as of September 12, 2013, among Forest Oil Corporation, the lenders signatory thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed September 18, 2013 (File No. 001-13515).
10.1	*	Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 4.1 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.2	*	Amendment No. 1 to Forest Oil Corporation’s 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2003 (File No. 001-13515).
10.3	*	Amendment No. 2 to Forest Oil Corporation’s 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2004 (File No. 001-13515).
10.4	*	Amendment No. 3 to Forest Oil Corporation 2001 Stock Incentive Plan, dated January 10, 2006, incorporated herein by reference to Exhibit 10.8 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.5	*	Amendment No. 4 to Forest Oil Corporation 2001 Stock Incentive Plan dated June 5, 2007, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.6	*	Form of Employee Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.7	*	Form of Non-Employee Director Stock Option Agreement, incorporated herein by reference to Exhibit 4.3 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).

10.8	*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.9	*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.12 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.10	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
10.11	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).

Exhibit Number		Description
10.12	*	Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Annex E to Forest Oil Corporation's Registration Statement on Form S-4, dated April 30, 2007 (File No. 333-140532).
10.13	*	Amendment No. 1 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.14	*	Amendment No. 2 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 12, 2010 (File No. 001-13515).
10.15	*	Amendment No. 3 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2011 (File No. 001-13515).
10.16	*	Amendment No. 4 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.6 to Form 8-K for Forest oil Corporation filed December 21, 2012 (File No. 001-13515).
10.17	*	Amendment No. 5 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 7, 2013 (File No. 001-13515).
10.18	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
10.19	*	Form of Non-Employee Director Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2008 (File No. 001-13515).
10.20	*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.21	*	Form of Restricted Stock Inducement Award Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.22	*	Form of CEO Restricted Stock Award Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.23	*	Form of 2013 Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - Cliff Vest, incorporated herein by reference to Exhibit 10.22 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).

10.24	*	Form of 2013 Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - One-Third Vest, incorporated herein by reference to Exhibit 10.23 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.25	*	Form of 2013 Restricted Stock Award Agreement - Cliff Vesting (updated), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.26	*	Form of 2013 Restricted Stock Award Agreement - Annual Vesting (updated), incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).

Exhibit Number		Description
10.27	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.28	*	Form of Non-Employee Director Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.29	*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2009 (File No. 001-13515).
10.30	*	Form of Phantom Stock Unit Agreement (Cash Only Three Vesting Tranches) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2011 (File No. 001-13515).
10.31	*	Form of Phantom Stock Unit Agreement (4-Year Pro-Rated Vesting) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed November 14, 2012 (File No. 001-13515).
10.32	*	Form of 2013 Cash Only Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - Cliff Vest, incorporated by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.33	*	Form of 2013 Cash Only Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan - One-Third Vest, incorporated by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2012 (File No. 001-13515).
10.34	*	Form of 2013 Phantom Stock Unit Award Agreement - Cliff Vesting (updated), incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.35	*	Form of 2013 Phantom Stock Unit Award Agreement - Annual Vesting (updated), incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.36	*	Form of Performance Unit Award Agreement (US) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.37	*	Form of Forest Oil Corporation Performance Unit Award Agreement - 2012, pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed March 16, 2012 (File No. 001-13515).
10.38	*	Form of CEO Plan Performance Unit Award Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 8-K to Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).

10.39	*	Form of Performance Unit Inducement Award Agreement, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.40	*	Form of 2013 Performance Unit Award Agreement - Stock Settled, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.41	*	Form of 2013 Performance Unit Award Agreement - Cash Settled, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed May 24, 2013 (File No. 001-13515).
10.42	*	Form of Cash-Based Award Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 13, 2011 (File No. 001-13515).

Exhibit Number		Description
10.43	*	Form of Forest Oil Corporation Cash-Based Award Agreement - 2012, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed May 16, 2012 (File No. 001-13515).
10.44	*	Form of Time-Based Cash Award Agreement, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed November 14, 2012 (File No. 001-13515).
10.45	*	Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.46	*	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.47	*	Form of 409A Amendment to Severance Agreement for Grandfathered Vice President and Senior Vice President – No 5-Day Release Provision, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2012 (File No. 001-13515).
10.48	*	Form of CEO Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed October 1, 2012 (File No. 001-13515).
10.49	*	Amendment to CEO Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.50	*	Form of SVP Best Net Severance Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.51	*	Form of SVP Best Net Grandfathered Severance Agreement, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No.001-13515).
10.52	*	Form of VP Best Net Severance Agreement, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).
10.53	*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002, dated November 14, 2002 (File No. 001-13515).
10.54	*	First Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2005, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2005 (File No. 001-13515).
10.55	*	Second Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2006, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation dated August 9, 2006 (File No. 001-13515).
10.56	*	

		Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.41 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.57	*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 9, 2009 (File No. 001-13515).
10.58	*	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated by reference to Exhibit 10.50 to form 10-K for Forest Oil Corporation for the fiscal year ended December 31, 2011 (File No. 001-13515).
10.59	*	Third Amendment to Forest Oil Corporation Executive Deferred Compensation Plan, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed December 21, 2012 (File No. 001-13515).

Exhibit Number		Description
10.60	*	Forest Oil Corporation 2011 Annual Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed August 16, 2011 (File No. 001-13515).
10.61	*	Forest Oil Corporation 2012 Annual Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed January 10, 2012 (File No. 001-13515).
10.62	*	Forest Oil Corporation 2013 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed May 17, 2013 (File No. 001-13515).
10.63		Separation and Distribution Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.64		Transition Services Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.65		Tax Sharing Agreement dated May 25, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.66		Employee Matters Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.67		Registration Rights Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation filed June 1, 2011 (File No. 001-13515).
10.68		Registration Rights Agreement, dated as of September 17, 2012, by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P. Morgan Securities LLC, as representative for the Initial Purchasers, incorporated herein by reference to Exhibit 4.2 to Form 8-K for Forest Oil Corporation filed September 17, 2012 (File No. 001-13515).
10.69		Share Purchase and Sale Agreement, effective as of March 31, 2012, by and among African International Energy PLC, Forest Oil Corporation, Anschutz South Africa Corporation, Forest Exploration International (South Africa) (Proprietary) Ltd and Anschutz Overseas (South Africa) (Proprietary) ltd, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed April 13, 2012 (File No. 001-13515).
10.70		Share Purchase and Sale Agreement, effective as of March 31, 2012, by and between African International Energy PLC and Forest Oil Netherlands BV, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed April 13, 2012 (File No. 001-13515).
10.71		Agreement for Purchase and Sale of Assets, dated as of October 11, 2012, by and between Forest Oil Corporation and Texas Petroleum Investment Company, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 12, 2012 (File No. 001.13515).

10.72	Agreement, dated as of October 22, 2012, by and among Forest Oil Corporation, Richard J. Carty, West Face Capital Inc. and West Face Long Term Opportunities Global Market L.P., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed October 24, 2012 (File No. 001-13515).
10.73	Confidentiality Agreement, dated October 22, 2012, by and between Forest Oil Corporation and West Face Capital Inc., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation filed October 24, 2012 (File no. 001-13515).
10.74	Agreement for Purchase and Sale of Assets, dated as of January 2, 2012, by and between Forest Oil Corporation, Forest Oil Permian Corporation, and Forcenergy Onshore Inc. (as Seller) and Hilcorp Energy I, L.P. (as Purchaser), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed January 3, 2012 (File No. 001-13515).

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10.75		Purchase Agreement, dated as of September 12, 2013, by and among Forest Oil Corporation, Forest Oil Permian Corporation and the Initial purchasers named therein, incorporated herein by reference to Exhibit 1.1 to Form 8-K for Forest Oil Corporation filed September 18, 2013 (File No. 001-13515).
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