

Well Processing
Section

MAK 97012

Washington DC
403



FOREST OIL

ANNUAL REPORT 2011

GROWING THE OIL IN FOREST

- Completed the spin-off of Lone Pine Resources Inc.
- Net sales volumes of 335 MMcfe/d
- Liquids net sales volumes of 15.5 MBbls/d
- Completed 25 Granite Wash wells in the Texas Panhandle with an average 24-hour initial production rate of 13 MMcfe/d (50% liquids)
- Completed three Missourian Wash wells in the Texas Panhandle with an average 24-hour initial production rate of 3,800 Boe/d (86% liquids)
- Completed 16 Eagle Ford Shale wells in South Texas with a maximum average 24-hour production rate of 634 Boe/d (93% oil)
- Completed two Cotton Valley wells in East Texas with an average 24-hour initial production rate of 8 MMcfe/d (34% liquids)
- Acquired 236,900 gross acres (195,500 net) in highly prospective oil and liquids-rich areas
- Drill bit reserve replacement ratio of 247% with finding and development costs of \$2.27 per Mcfe
- All-sources reserve replacement ratio of 148% with finding and development costs of \$3.77 per Mcfe
- Adjusted EBITDA of \$551 million
- Adjusted discretionary cash flow of \$408 million

2011 Highlights

* The information contained throughout this annual report, unless otherwise indicated, relates only to the retained operations of Forest and excludes the operations of Lone Pine Resources Inc. from the current and historic periods.

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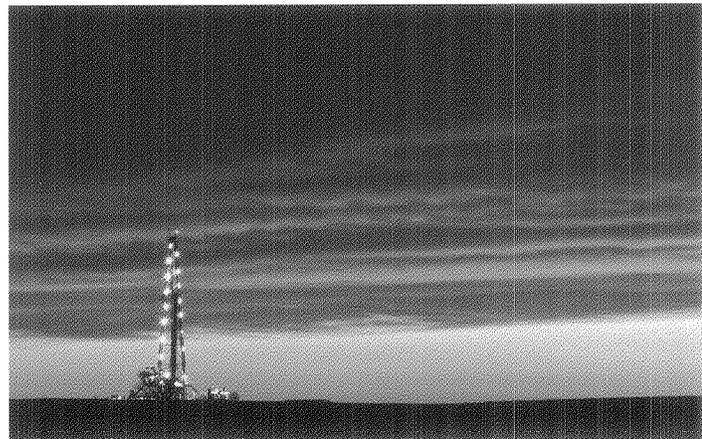
FELLOW SHAREHOLDERS

Last year was a transformative year at Forest as we completed the spin-off of our Canadian assets and distributed another large dividend to our shareholders, this time in the form of Lone Pine Resources stock. We thank Lone Pine's management team and employees for the success of the transaction. Additionally, we wish them the best of luck in the future. The two of us, and in fact all the employees of Forest, became shareholders of Lone Pine as a result of the spin-off. This transaction instantly focused each company on the geographic and geologic areas that are their strength — Canada for Lone Pine and the U.S. for Forest. Forest is now more focused on growing oil and liquids production in the U.S. from a larger inventory of liquids-rich drilling opportunities than ever before, giving us the ability to **“Grow the Oil in Forest.”**

We were confronted with two substantial challenges in 2011. The first challenge related to disappointing results from the Granite Wash in the Texas Panhandle in early 2011, following several years of excellent performance. The second challenge related to low natural gas prices, which became substantially disconnected from oil prices, resulting in oil trading at all-time high multiples relative to natural gas.

To confront these challenges, we have taken two broad steps. First, we have diversified our capital allocation and drilling program to a more balanced geographic and geologic approach. In the second half of 2011, we successfully completed wells in the Texas Panhandle in previously undrilled oil intervals above the Granite Wash. In the Eagle Ford Shale oil window in South Texas, we completed 16 oil wells while performing significant science and data accumulation, and believe we have identified the optimal completion interval and method. In East Texas/North Louisiana, we completed two horizontal wells targeting a Cotton Valley interval that is oil-bearing and natural gas liquids-rich, and have identified a number of additional liquids-rich horizontal opportunities in the Cotton Valley for future development.

Second, we dramatically expanded our acreage position targeting oil and liquids-rich plays. In 2011, and into early 2012, we acquired 114,500 net oil and liquids-rich prospective acres in the Permian Basin for approximately \$150 million, or under \$1,300 per acre. By identifying these oil and liquids-rich targets early in their life cycle, we are able to capture prime acreage prior to the acreage cost acceleration. This, in turn, should allow us to realize higher full-cycle returns through organic development of these plays, while creating a significant oil and liquids-rich project inventory. Forest has always maintained an excellent track record on cost control and efficiencies, and we believe we can now add inexpensive organic play generation to our list of core competencies.



Growing the Oil in Forest

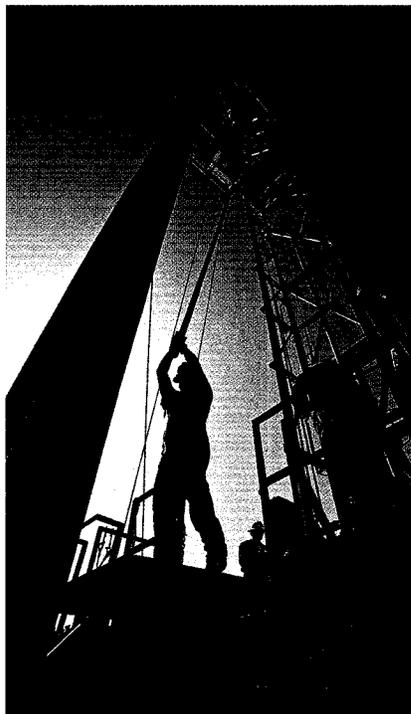
While in 2011 we spent a significant amount of capital on leasehold acquisitions, 2012 will be focused on organically growing our oil and liquids production, delineating our newly-acquired oil and liquids-rich plays, and keeping our spending within a reasonable bandwidth of cash flow.

The Texas Panhandle will be the beneficiary of the majority of the capital budget due to the highly prolific oil and natural gas liquids production generated from the Granite Wash intervals and newly-discovered uphole oil intervals. The remainder of the capital budget will be split between oil projects in the Eagle Ford Shale, the Wolfcamp and Wolfbone plays in the Permian Basin (which we refer to as the “Wolfpack”), liquids-rich projects in East Texas, and natural gas in the Haynesville/Bossier Shale in North Louisiana. Our deep inventory across oil, natural gas liquids, and natural gas basins allows us to select projects that achieve the best returns over a multiple-year investment horizon.

In keeping with our continued focus on returns, we maintain our belief that profitability is not just determined by the current commodity price. We believe that by adhering to the cost conscious structure of our organization, we can better control the bottom line and enhance returns.

Through the utilization of our subsidiary Lantern Drilling and keeping at the forefront of technological advancements in completion designs, we expect to continue to be one of the lowest cost operators in the industry while always striving to improve upon our extraction and cost efficiencies.

In closing, we look back on a transformative year for Forest Oil. Our continued focus on oil and liquids-rich development and grassroots generation of oil projects, should enable us to provide profitable organic growth in multiple geographic areas in 2012. We again thank our shareholders for their continued support as well as our dedicated employees for all of their efforts. We look forward to “**Growing the Oil in Forest**” and building on our successes in 2012.



Handwritten signature of James D. Lightner.

James D. Lightner
Chairman of the Board

Handwritten signature of H. Craig Clark.

H. Craig Clark
President and Chief Executive Officer

Forest's core areas consist of a well-balanced portfolio of tight sands, carbonates, and shale plays in the United States, most with multiple stacked-pay opportunities for oil, natural gas liquids, and natural gas. Initial vertical delineation drilling in many of our core areas has established the existence of consistent geologic trends, creating what we believe to be low-risk, repeatable development opportunities. Forest initially exploited the majority of its core operational areas through vertical development, but with the emergence of new drilling and completion technology, Forest has transitioned the development of a majority of these plays to horizontal development. Through the application of horizontal drilling, Forest seeks to enhance initial production rates and estimated ultimate recoveries while focusing on reducing drilling and completion costs. The Company's primary areas of focus in 2012 will be in the Texas Panhandle, the Eagle Ford Shale in South Texas, the Permian Basin, and in East Texas/North Louisiana, with the majority of capital expenditures allocated to oil and liquids-rich projects, from which the Company intends to continue **"Growing the Oil in Forest."**

Western

Forest has approximately 109,000 net acres in the **Texas Panhandle**, establishing the Company as one of the top acreage holders in the area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as oil-rich objectives including the Cleveland and Missourian Wash. Forest drilled its first horizontal wells in the area in 2009, leveraging its vertical delineation database of over 600 wells to determine the most attractive intervals in which to initiate a horizontal drilling campaign. Based on significant results achieved through the 2009 horizontal drilling program, Forest increased its horizontal development rig count from one to five rigs, developing known productive intervals and establishing new prospective intervals for future horizontal drilling efforts. In total, Forest has successfully tested seven liquids-rich intervals as prospective for horizontal development in the Granite Wash. With the favorable price of condensate and natural gas liquids relative to natural gas, this liquids-rich play provides superior rates of return compared to other natural gas plays in North America. Additionally, during 2011, Forest successfully tested numerous prospective oil intervals, including the shallow Cleveland and the Missourian Wash, which expands the horizontal oil drilling potential within the Texas Panhandle. With respect to its entire Texas Panhandle operations, Forest has tested a total of 11 intervals as prospective for horizontal development. In 2012, Forest plans to run a five to six rig drilling program targeting the Granite Wash and other prospective oil intervals, including the Cleveland and Missourian Wash.



Southern/New Ventures

Forest has approximately 103,000 net acres in the Eagle Ford Shale, primarily located in Gonzales County in **South Texas**. The area provides Forest with access to the oil-bearing section of the Eagle Ford Shale and provides an oil development opportunity through the application of horizontal drilling and completion technologies. The Company commenced the drilling of its first horizontal well in the Eagle Ford

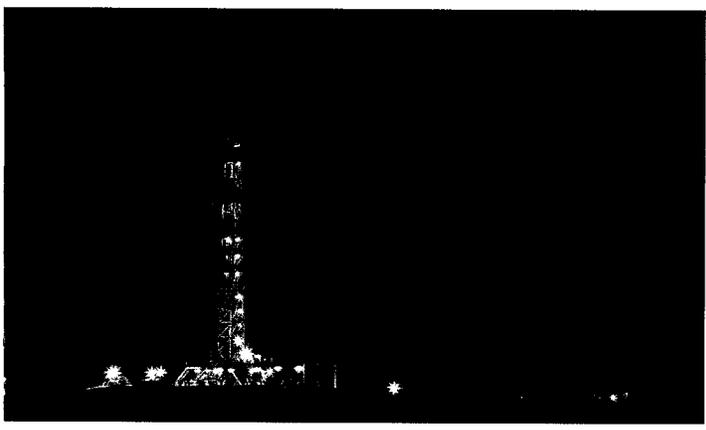
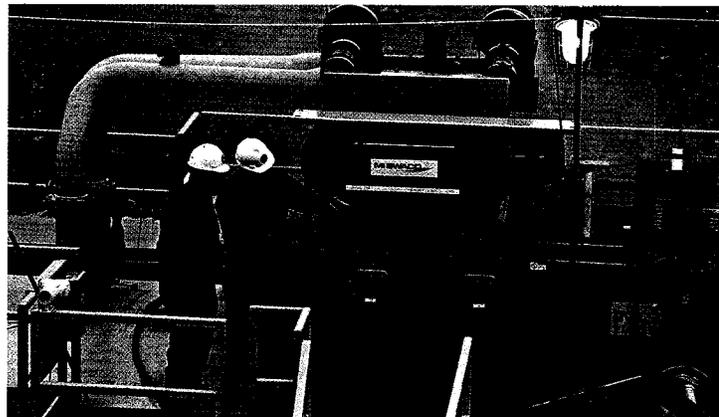
oil window at the end of 2010 and expanded the program in 2011 to focus on the optimization of the development operations. This optimization included taking core samples, acquiring 3-D seismic, the utilization of micro-seismic technology during horizontal well completions, and testing different sections of the Eagle Ford Shale, all with the goal of finding the optimal section to land the lateral and the most effective and efficient methods to stimulate the wells. The optimization efforts have resulted in Forest targeting the upper-most member of the Eagle Ford for lateral placement and employing a less

intensive fracture stimulation treatment. In 2012, Forest plans to run a one rig drilling program in the Eagle Ford Shale.

In addition, Forest has accumulated approximately 114,500 net oil and liquids-rich prospective acres in the **Permian Basin**. The area provides exposure to numerous oil objectives, both vertically and horizontally. The acreage is concentrated in large contiguous positions in both the Delaware and Midland Basins. In 2012, Forest plans to run a one rig drilling program in the Permian Basin.

Eastern

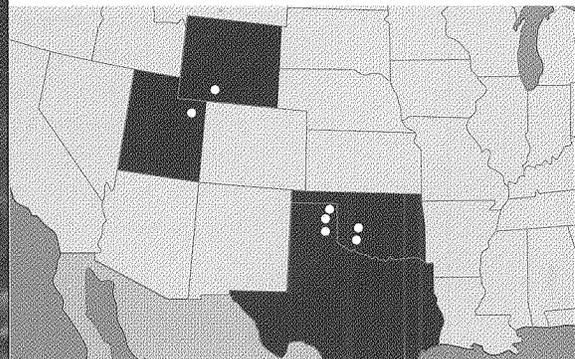
Forest has approximately 125,000 net acres in the **East Texas/North Louisiana** area. The area provides for both horizontal and vertical drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville/Bossier Shale, Pettit, and other formations. In 2010, the Company's development program was focused in the Haynesville/Bossier Shale in North Louisiana where it drilled 20 horizontal wells that had an average 24-hour initial production rate of 16 MMcf/d. In an effort to optimize recovery from Haynesville/Bossier Shale wells, Forest instituted a restricted flow rate production program in late-2010. Under this program, initial production rates from the last six wells were restricted to approximately 11 MMcf/d. In 2011, Forest initially reduced drilling and completions efforts in the Haynesville/Bossier Shale in North Louisiana and the Cotton Valley in East Texas in order to monitor the results from the restricted flow rate program and as a result of increasing service costs. By the end of 2011, Forest re-entered the plays as a result of positive performance from its restricted flow rate production program in the Haynesville/Bossier Shale, significant reductions in drilling and completion costs in the region, and liquids-rich drilling opportunities in the Cotton Valley. In 2012, Forest plans to run a one rig pad drilling program in North Louisiana targeting the Haynesville/Bossier Shale and a one rig drilling program in East Texas targeting the liquids-rich Cotton Valley.



Operational Fact SHEET

WESTERN

	2011	2010	2009
NET PRODUCTION			
Gas (MMcf/d)	74.6	77.0	80.2
Liquids (MMbbls/d)	9.1	10.0	10.2
ESTIMATED PROVED RESERVES			
Gas (Bcf)	429.2	394.7	362.9
Liquids (MMBbls)	39.6	35.3	27.8
Equivalent (Bcfe)	666.8	606.6	529.9
DEVELOPED ACREAGE			
Gross	244,588	252,679	258,123
Net	119,441	119,918	119,580
UNDEVELOPED ACREAGE			
Gross	236,591	228,340	211,305
Net	101,987	124,033	121,513
GROSS WELL COUNT			
Gas	1,032	972	928
Oil	62	62	66
CAPITAL EXPENDITURES In thousands			
	\$283,685	\$225,659	\$147,517

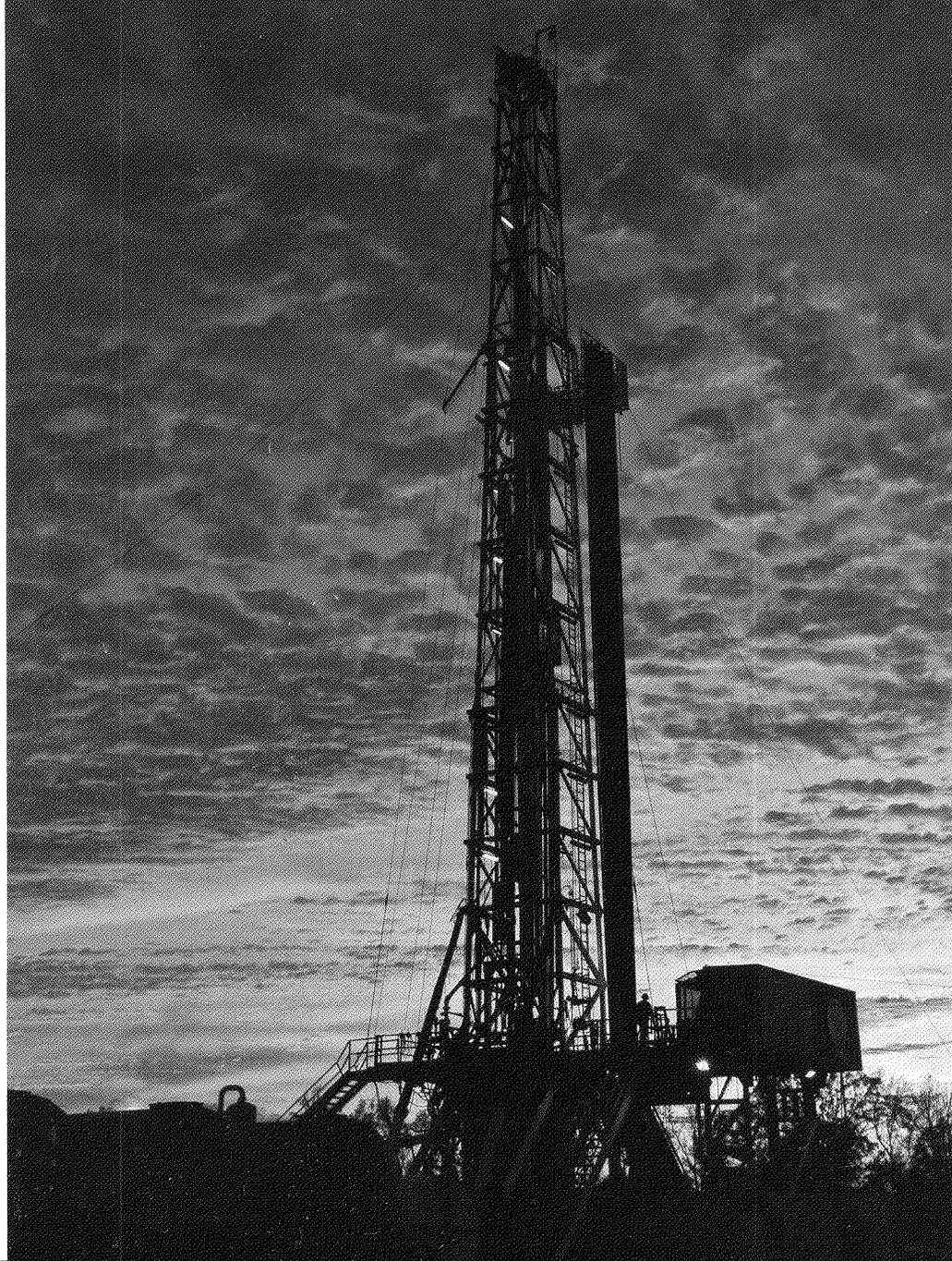


2011 HIGHLIGHTS

- Year-end estimated proved reserves of 667 Bcfe with a drill bit reserve replacement ratio of 288% and a finding and development cost of \$2.09
- Drilled 68 gross wells with a 99% success rate
- Successfully completed 25 Granite Wash wells with an average 24-hour initial production rate of 13 MMcfe/d (50% liquids)
- Successfully completed three Missourian Wash wells with an average 24-hour initial production rate of 3,800 Boe/d (86% liquids)
- Established a total of 11 intervals as currently commercial with five additional intervals identified as prospective for horizontal drilling

2012 STRATEGY

- Drilling program calls for approximately 30 gross operated wells and a continued high pace of additional projects
- Drilling program designed to develop Granite Wash liquids and shallow oil in the Texas Panhandle in addition to testing new intervals prospective for horizontal drilling
- Targeting a two to three rig drilling program in the Granite Wash intervals
- Targeting a two to three rig drilling program in the Missourian Wash, Cleveland, and additional oil intervals
- Leverage the Lantern Drilling rig fleet and test new completion techniques to manage cost



SOUTHERN/NEW VENTURES

	2011	2010	2009
NET PRODUCTION			
Gas (MMcf/d)	71.5	89.9	114.3
Liquids (MMBbls/d)	3.0	2.5	2.6
ESTIMATED PROVED RESERVES			
Gas (Bcf)	235.7	252.0	312.8
Liquids (MMBbls)	16.9	6.3	6.3
Equivalent (Bcfe)	337.0	289.6	350.6
DEVELOPED ACREAGE			
Gross	215,675	175,697	211,979
Net	150,428	109,668	139,137
UNDEVELOPED ACREAGE			
Gross	245,839	126,616	121,742
Net	208,998	113,094	107,718
GROSS WELL COUNT			
Gas	1,047	1,059	1,300
Oil	79	67	65
CAPITAL EXPENDITURES In thousands			
	\$285,576	\$93,810	\$76,740

EASTERN

	2011	2010	2009
NET PRODUCTION			
Gas (MMcf/d)	96.3	110.8	123.4
Liquids (MMBbls/d)	3.4	3.8	4.8
ESTIMATED PROVED RESERVES			
Gas (Bcf)	731.7	787.1	739.8
Liquids (MMBbls)	19.5	22.1	21.0
Equivalent (Bcfe)	848.9	919.7	866.0
DEVELOPED ACREAGE			
Gross	222,904	225,692	233,235
Net	160,528	163,986	167,475
UNDEVELOPED ACREAGE			
Gross	47,652	98,368	130,835
Net	25,904	62,870	71,665
GROSS WELL COUNT			
Gas	1,506	1,491	1,507
Oil	223	232	240
CAPITAL EXPENDITURES In thousands			
	\$106,730	\$169,813	\$204,955

INTERNATIONAL

	2011	2010	2009
NET PRODUCTION			
Gas (MMcf/d)	—	—	—
Liquids (MMBbls/d)	—	—	—
ESTIMATED PROVED RESERVES			
Gas (Bcf)	51.7	51.7	51.7
Liquids (MMBbls)	—	—	—
Equivalent (Bcfe)	51.7	51.7	51.7
DEVELOPED ACREAGE			
Gross	—	2,500	2,500
Net	—	2,250	2,250
UNDEVELOPED ACREAGE			
Gross	2,878,738	3,060,238	3,060,238
Net	1,561,049	1,705,999	1,705,999
GROSS WELL COUNT			
Gas	2	2	2
Oil	—	—	—
CAPITAL EXPENDITURES In thousands			
	\$6,976	\$4,153	\$9,186

2011 HIGHLIGHTS

- Year-end estimated proved reserves of 337 Bcfe with a drill bit reserve replacement ratio of 340% and a finding and development cost of \$2.58
- Drilled 32 gross wells with a 91% success rate
- Successfully completed 16 Eagle Ford Shale wells with a maximum average 24-hour production rate of 634 Boe/d (93% oil)
- Continued New Ventures grassroots leasing program adding 197,000 gross acres (164,000 net) at a cost of approximately \$750 per acre

2012 STRATEGY

- Drilling program calls for approximately 15 gross operated wells and a continued high pace of additional projects
- Drilling program designed to further delineate the Eagle Ford Shale, with primary focus on Gonzales County, and to test oil opportunities in the Permian Basin
- Targeting a one rig drilling program in the Eagle Ford Shale utilizing a 1,000 horsepower rig to manage cost
- Targeting a one rig drilling program in the Permian Basin utilizing a 1,000 horsepower rig to manage cost

2011 HIGHLIGHTS

- Year-end estimated proved reserves of 849 Bcfe with a drill bit reserve replacement ratio of 127% and a finding and development cost of \$1.97
- Drilled 27 gross wells with a 100% success rate
- Successfully completed two Cotton Valley wells with an average 24-hour initial production rate of 8 MMcf/d (34% liquids)
- Successfully completed three Haynesville/Bossier Shale wells with an average 24-hour restricted initial production rate of 11 MMcf/d

2012 STRATEGY

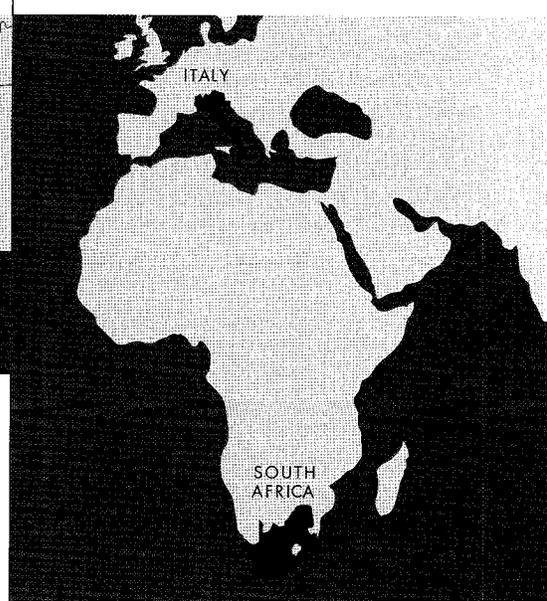
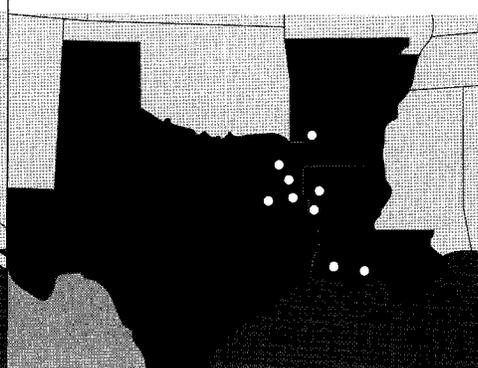
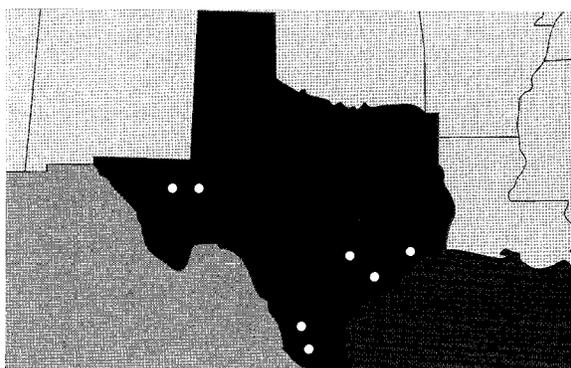
- Drilling program calls for approximately 20 gross operated wells and a continued high pace of additional projects
- Drilling program designed to develop Cotton Valley in East Texas and the Haynesville/Bossier Shale in North Louisiana and capitalize on declining service cost environment and utilization of pad drilling to manage cost
- Targeting a one rig drilling program in the Cotton Valley in East Texas
- Targeting a one rig drilling program in the Haynesville/Bossier Shale in North Louisiana
- Leverage the Lantern Drilling rig fleet and test new completion techniques to manage cost

2011 HIGHLIGHTS

- Year-end estimated proved reserves of 52 Bcfe
- Continued progress to commence production from Monte Pallano property in Italy that tested at an average initial production rate of 22 MMcf/d without fracture stimulation
- Continued progress to secure gas contracts in South Africa

2012 STRATEGY

- Continue progress toward achieving production licenses in Italy
- Continue progress in securing gas contracts in South Africa



Executive Officers

H. CRAIG CLARK, 55
President and
Chief Executive Officer
Years of Service: 11

MICHAEL N. KENNEDY, 37
Executive Vice President
and Chief Financial Officer
Years of Service: 11

JOHN C. RIDENS, 56
Executive Vice President
and Chief Operating Officer
Years of Service: 8

CECIL N. COLWELL, 61
Senior Vice President,
Worldwide Drilling
Years of Service: 23

CYRUS D. MARTER IV, 48
Senior Vice President,
General Counsel and Secretary
Years of Service: 10

GLEN J. MIZENKO, 49
Senior Vice President,
Eastern Region
Years of Service: 11

VICTOR A. WIND, 38
Senior Vice President,
Chief Accounting Officer and
Corporate Controller
Years of Service: 7

RONALD C. NUTT, 54
Vice President, Southern Region
Years of Service: 5

Board of Directors

LOREN K. CARROLL, age 68, has been a director since 2006. Mr. Carroll served as President and Chief Executive Officer of M-I SWACO, a supplier of drilling and completion fluids and waste management products and services owned 60% by Smith International, Inc., and as Executive Vice President of Smith International, Inc., a supplier of products and services to the oil and gas, petrochemical, and other industrial markets from March 1994 until his retirement in April 2006. He initially joined Smith International in December 1984, and was serving as Executive Vice President and Chief Financial Officer when he left in 1989 and when he returned in October 1992. Mr. Carroll is a director of CGG-Veritas, a geophysical services and equipment company, and KBR, Inc., an engineering and construction company. Mr. Carroll previously served as a director of Smith International, Inc. and Fleetwood Enterprises, Inc., a producer of recreational vehicles and manufactured homes. Mr. Carroll is a member of our Compensation Committee and is Chairman of the Nominating and Corporate Governance Committee. Mr. Carroll graduated from California State University at Long Beach with a bachelor of science degree in accounting.

H. CRAIG CLARK, age 55, has served as our President and Chief Executive Officer and as a director of Forest since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions including Executive Vice President—U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache. Mr. Clark is a member of our Executive Committee. Mr. Clark graduated from Texas A&M University with a bachelor of science degree in engineering.

DOD A. FRASER, age 61, has been a director since 2000. Mr. Fraser is President of Sackett Partners Incorporated, a consulting company, and a member of corporate boards, since 2000. Previously, Mr. Fraser was an investment banker, a General Partner of Lazard Freres & Co. and, most recently, Managing Director and Group Executive of Chase Manhattan Bank, now JP Morgan Chase, where he led the global oil and gas group. Mr. Fraser was a board member of Smith International, Inc., an oilfield service company, and Terra Industries, Inc., a nitrogen-based fertilizer company. Mr. Fraser is a board member of Subsea 7 S.A., a sub-sea engineering and contracting company. Mr. Fraser serves as Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee. Mr. Fraser graduated from Princeton University with a bachelor of arts degree.

JAMES D. LIGHTNER, age 59, has been a director since 2004 and has served as our non-executive Chairman of the Board since May 2008. Mr. Lightner has been Chief Executive Officer of Beacon E&P Company, an oil and gas exploration company, since its inception in 2009. Mr. Lightner was a Partner and Chief Executive Officer of Orion Energy Partners, an oil and gas exploration and production company, from its inception in August 2004 until its winding down in 2009. From 1999 to 2004, Mr. Lightner served in various capacities with Tom Brown, Inc., an oil and gas exploration and production company, including director, Chairman, Chief Executive Officer and President, until its sale to EnCana Oil & Gas (USA) Inc. in 2004. Prior to 1999, he served as Vice President and General Manager of EOG Resources, Inc., a publicly traded oil and gas exploration and production company. Mr. Lightner had been a director since November 2004

of W-H Energy Services Inc., an oil field services company, until its sale in July 2008. Mr. Lightner serves as Chairman of our Executive Committee and as a member of our Nominating and Corporate Governance Committee. Mr. Lightner received a bachelor of science degree in geology from Southern Illinois University, and a master of science degree in geology from the Australian National University.

JAMES H. LEE, age 63, has been a director since 1991. Mr. Lee has served as the Managing General Partner of Lee, Hite & Wisda Ltd., an oil and gas consulting and exploration firm, since 1984. Mr. Lee has been a director of Holly Frontier Oil Corporation, successor to Frontier Oil Corporation, a crude oil refining and wholesale marketing company, since 2000. He is a member of our Audit Committee and our Executive Committee. Mr. Lee graduated from Stanford University with a bachelor of arts degree in economics and from The Harvard Graduate School of Business Administration with an MBA.

PATRICK R. MCDONALD, age 54, has been a director since 2004. He was appointed as the Chief Executive Officer, President and as a Director and Chairman of the Board of Directors of Carbon Natural Gas Co. on February 14, 2011 and served as Chief Executive Officer, President and Director of its predecessor company Nytris USA since 2004. In March 2011, Mr. McDonald was elected as a director of Lone Pine Resources Inc., an oil and gas exploration, development and production company. 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. Mr. McDonald is a member of our Audit Committee and serves as chairman of the Compensation Committee. He is a Certified Petroleum Geologist and is a member of the American Association of Petroleum Geologists and Canadian Society of Petroleum Geologists. Mr. McDonald received a bachelor's degree in geology and economics from Ohio Wesleyan University and an MBA in Finance from New York University.

RAYMOND I. WILCOX, age 66, has been a director since 2009. Mr. Wilcox served as President and Chief Executive Officer of Chevron Phillips Chemical Company LLC, producers of olefins and polyolefins, aromatics, alpha olefins, styrenics and specialty chemicals, from April 2006 until his retirement in March 2008. From 2002 until 2006, Mr. Wilcox served as Vice President of Chevron Corporation, a worldwide integrated energy company, and President of Chevron North America Exploration and Production Company, an oil and gas exploration and production company. Mr. Wilcox joined Chevron in 1968 and his career covered responsibilities in the upstream, midstream and chemical segments, and included activities in North America, Indonesia, Australia, Kazakhstan, the Far East, the Middle East and Africa. Mr. Wilcox previously served as a director of Dynege, Inc. from June 2003 until March 2006. Mr. Wilcox is a member of our Nominating and Corporate Governance Committee and our Compensation Committee. He graduated from the University of Michigan with a bachelor of science degree in mechanical engineering.

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

For the transition period from to

Commission File Number: 1-13515

FOREST OIL CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

State of incorporation: **New York**
707 17th Street - Suite 3600 - Denver, Colorado
(Address of Principal Executive Offices)

I.R.S. Employer Identification No. **25-0484900**
80202
(Zip Code)

Registrant's telephone number, including area code: **(303) 812-1400**

Securities registered pursuant to Section 12(b) of the Act:

<u>Title of Each Class</u>	<u>Name of Each Exchange on which Registered</u>
Common Stock, Par Value \$.10 Per Share	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, was \$3,024,434,519 (based on the closing price of such stock).

There were 117,210,156 shares of the registrant's common stock, par value \$.10 per share, outstanding as of February 16, 2012.

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, 2011 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

	<u>Page No.</u>
PART I	
Item 1. Business	1
Item 1A. Risk Factors	14
Item 1B. Unresolved Staff Comments.....	17
Item 2. Properties	17
Item 3. Legal Proceedings	18
Item 4. Mine Safety Disclosures.....	18
Item 4A. Executive Officers of Forest.....	19
PART II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.....	20
Item 6. Selected Financial Data	22
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	23
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	38
Item 8. Financial Statements and Supplementary Data	41
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.....	93
Item 9A. Controls and Procedures.....	93
Item 9B. Other Information.....	93
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	95
Item 11. Executive Compensation	95
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	95
Item 13. Certain Relationships and Related Transactions, and Director Independence	95
Item 14. Principal Accounting Fees and Services.....	95
PART IV	
Item 15. Exhibits, Financial Statement Schedules.....	96
Signatures	102

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 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, 2011 were approximately 1,904 Bcfe. At December 31, 2011, approximately 97% of Forest's estimated proved oil and gas reserves were in the United States.

In June 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 of record as of September 16, 2011, by means of a special stock dividend of Lone Pine common shares. As a result of the spin-off, Lone Pine is reported as a discontinued operation throughout this Form 10-K. See "Acquisition and Divestiture Activities" below for more information on the initial public offering and subsequent spin-off of Lone Pine.

Strategy

Following the spin-off of Lone Pine, Forest implemented a long-term operating strategy intended to increase shareholder value through the achievement of organic production and reserve growth while maintaining a capital expenditure budget that approximates cash flow from operating activities. Forest believes measured growth can be achieved through this strategy by focusing capital expenditures primarily on developing Forest's core operational areas located in the Texas Panhandle, East Texas / North Louisiana, and in the Eagle Ford Shale in South Texas. In addition, our growth may be supplemented from time to time through opportunistic acquisitions. We endeavor to execute this strategy as follows:

Exploit and develop resource plays for measured production and reserve growth while maintaining a capital expenditure budget that approximates cash flow from operating activities. In our efforts to grow production and reserves, we plan to continue to apply the latest technologies to our resource plays, including horizontal drilling and multi-stage hydraulic fracture stimulation techniques. We believe these technologies provide for efficient production and reserve growth from our diverse portfolio of shale and conventional oil and gas acreage positions. Our core operational areas have a large number of remaining commodity-diverse drilling locations, providing what we believe to be are repeatable development opportunities. In 2012, due to a low natural gas price environment, we intend to devote the majority of our exploration and development expenditures to oil and liquids projects, including approximately 50% in the Texas Panhandle where liquids-rich Granite Wash and shallow oil intervals are targeted. Further, due to the low natural gas price environment, we expect our capital expenditures will exceed our cash flows in 2012.

Focus on operational control, cost efficiencies, and high-margin projects. Our development efforts are focused in areas where we have concentrated land positions, a large drilling inventory, and operational control, which allow us to optimize our development plans and, therefore, reduce costs. Furthermore, our diverse portfolio allows us to allocate capital to projects with the highest margins, which currently include oil or liquids-rich drilling prospects. Our concentrated land positions, operational control, and focus on cost and margin allow us to achieve economies of scale and potentially provide for higher rates of return on invested capital.

Rationalize our asset base through leasehold and property acquisitions, divestitures, and exploration. We intend to pursue leasehold and property acquisitions to enhance existing business operations in our core operational areas and in new areas emphasizing grass roots leasing efforts at attractive entry cost, with a preference for liquids-rich hydrocarbon prospects. We also plan to pursue a measured exploration program in these areas through the utilization of our strong internal technical staff. As economic conditions permit, we intend to divest assets that do not fit our primary business strategy, including those without significant development opportunities.

Maintain financial flexibility. We intend to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and prudent financial management. Further, we intend to focus on reducing our debt levels relative to our estimated proved reserves and EBITDA and will consider joint ventures, divestitures, and other means to increase our financial flexibility.

Core Operational Areas

Forest's core areas consist of a well-balanced portfolio of tight-gas sands, carbonates, and shale plays with multiple stacked-pay opportunities in the United States that have exposure to oil, natural gas liquids, and natural gas. Initial vertical delineation drilling in many of our core areas has established the existence of consistent geologic trends, creating what we believe to be low-risk, repeatable development opportunities. Forest initially exploited the majority of its core operational areas through vertical development, but with the emergence of new drilling and completion technology, Forest has transitioned the development of a number of these plays to horizontal development. Through the application of horizontal drilling, Forest seeks to enhance initial production rates and estimated ultimate recoveries while focusing on reducing drilling costs. Our primary areas of focus in 2012 will be in the Texas Panhandle, East Texas / North Louisiana, and in the Eagle Ford Shale in South Texas.

Texas Panhandle

We have approximately 109,000 net acres in the Texas Panhandle, establishing Forest as one of the top acreage holders in this area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as oil-rich objectives including the Tonkawa, Cleveland, and Missourian Wash formations. We drilled our first horizontal wells in the area in 2009, leveraging our vertical delineation database of over 600 wells to determine the most attractive intervals to initiate a horizontal drilling campaign. Based on significant results achieved through the 2009 horizontal drilling program, Forest increased its horizontal development rig count from one to five rigs from 2009 to 2010, developing known productive intervals and establishing new prospective intervals for future drilling efforts. In total, Forest has successfully tested seven liquids-rich intervals as prospective for horizontal development in the Granite Wash. With the favorable price of condensate and natural gas liquids relative to natural gas, this liquids-rich play provides superior rates of return compared to other natural gas plays in North America. Additionally, during 2011, Forest successfully tested two prospective oil intervals, including the shallow Cleveland formation and the Missourian Wash (Hogshooter) formation, that expands the oil drilling potential within the Texas Panhandle. In total, Forest has tested 11 intervals as prospective for horizontal development in the Texas Panhandle. In 2012, we plan to run a five to six rig drilling program targeting the Granite Wash and other prospective intervals, including the Cleveland and Missourian Wash formations.

East Texas / North Louisiana

We have approximately 125,000 net acres in the East Texas / North Louisiana area. The area provides for both horizontal and vertical drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville, Pettit, and other formations. In 2010, our development program was focused in the Haynesville/Bossier Shale in North Louisiana where we drilled 20 horizontal wells that had average 24-hour initial production rates of 16 MMcfe/d. In an effort to optimize recovery from Haynesville/Bossier Shale wells, Forest instituted a restricted flow rate production program in late-2010. Under this program, initial production rates from the last six wells were curtailed at 11 to 15 MMcfe/d. In 2011, Forest reduced drilling and completions efforts in the Haynesville/Bossier Shale in North Louisiana and the Cotton Valley in East Texas due to increasing service costs. By the end of 2011, Forest re-entered the plays as a result of reductions in drilling and completion costs in the region, positive performance from its restricted rate production program in the Haynesville/Bossier Shale, and liquids-rich drilling opportunities in the Cotton Valley. In 2012, we plan to run a two rig drilling program in North Louisiana and East Texas.

South Texas—Eagle Ford Shale

We have approximately 103,000 net acres in the Eagle Ford Shale, primarily located in Gonzales County in South Texas. The area provides Forest with access to the oil-bearing section of the Eagle Ford and is expected to yield an oil development opportunity through the application of horizontal drilling and completion technologies. We commenced the drilling of our first horizontal well in the Eagle Ford oil window at the end of 2010 and expanded the program in 2011 to focus on the optimization of our development operations. This optimization included taking core samples, acquiring 3-D seismic, the utilization of micro-seismic during horizontal well completions, and testing different sections of the Eagle Ford Shale, all with the goal of finding the optimal section in the Eagle Ford in which to land the lateral and the most effective and efficient methods to complete the wells. Through Forest's optimization efforts undertaken in 2011 in the Eagle Ford Shale, we believe that we can ultimately generate economic production rates and recoveries. In 2012, we plan to run a one rig drilling program in the Eagle Ford Shale.

Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and are consistent with our North American onshore low-risk development focus, and we pursue divestitures of non-core assets to upgrade our portfolio and further increase our operational efficiencies. Acquisitions in and around our existing core areas enable us to leverage our cost control abilities, technical expertise, and existing land and infrastructure positions. In general, our acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage positions. The following sets forth our significant acquisitions and divestitures over the last several years.

Acquisitions

During 2011 and early 2012, we acquired 126,000 gross acres (114,500 net) prospective for oil production in the Permian Basin. The acreage position was established in areas prospective for both the Wolfcamp Shale in Crockett County, Texas, where Forest has 57,500 gross acres (51,500 net) and the Wolfbone zones in Pecos and Reeves Counties, Texas, where Forest has 68,500 gross acres (63,000 net). We believe this acreage position allows us access to significant oil drilling opportunities that we intend to pursue in 2012.

In September 2008, we acquired producing oil and natural gas properties located in our Texas Panhandle and East Texas / North Louisiana core areas from Cordillera Texas, L.P. for approximately \$570 million in cash and 7.25 million shares of our common stock, valued at approximately \$360 million. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 85,000 net acres.

In June 2007, we acquired The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately \$1.5 billion including the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, and acquisition of natural gas and oil reserves in North America. At the time of the acquisition, we estimated the Houston Exploration proved reserves to be 653 Bcfe. Pursuant to the terms and conditions of the agreement and plan of merger, Forest paid total merger consideration of \$750 million in cash and issued approximately 24 million shares of our common stock, valued at approximately \$726 million.

Divestitures

In December 2010, Forest announced its intention to separate its Canadian operations through an initial public offering of up to 19.9% of the common stock of its wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which would hold Forest's ownership interests in its Canadian operations, followed by a distribution, or spin-off, of the remaining shares of Lone Pine to Forest's shareholders. The initial public offering of Lone Pine occurred in June 2011, with Forest retaining approximately 82% of the outstanding shares of Lone Pine's common stock. Lone Pine used the net proceeds from the offering, along with borrowings under its credit facility, to pay approximately \$29 million to Forest, as partial consideration for the contribution to Lone Pine of Forest's interests in the Canadian operations, and to repay an intercompany note and intercompany advances and accrued interest of approximately \$401 million. The spin-off of Forest's remaining shares of Lone Pine to Forest shareholders was completed on September 30, 2011.

In 2009, we sold all of our oil and gas properties located in the Permian Basin in West Texas and New Mexico as well as other oil and gas properties in the U.S. for approximately \$933 million in cash. We estimated the proved reserves associated with these properties were 551 Bcfe at the closings of the relevant transactions.

In August 2007, we sold all of our assets located in Alaska to Pacific Energy Resources Ltd. ("PERL"), with such assets estimated to have proved reserves of 173 Bcfe at the time of closing. Total consideration received for the assets included \$400 million in cash as well as 10 million shares of PERL common stock and a zero coupon senior subordinated note from PERL due 2014 at a principal amount of \$61 million.

In March 2006, we completed a spin-off of our offshore Gulf of Mexico operations by means of a special dividend, which consisted of a pro rata spin-off of all outstanding shares of a Forest subsidiary that held our offshore Gulf of Mexico assets, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the spin-off, the Forest subsidiary was merged with a subsidiary of Mariner Energy, Inc. ("Mariner"), at which time the 50.6 million shares included in the spin-off were exchanged for an equal number of Mariner common shares. Mariner's common stock commenced trading on the New York Stock Exchange ("NYSE") on March 3, 2006. We estimated the proved reserves associated with the spin-off to be 313 Bcfe at the time of closing.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2011, based on the Henry Hub price of \$4.12 per MMBtu for natural gas and the West Texas Intermediate price of \$96.08 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, 2011. See—"Preparation of Reserves Estimates" below and Note 15 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves			
	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Total (MMcfe) ⁽¹⁾
Developed:				
United States	814,160	14,149	23,170	1,038,074
Italy.....	—	—	—	—
Total developed.....	814,160	14,149	23,170	1,038,074
Undeveloped:				
United States	582,356	17,444	21,259	814,574
Italy.....	51,738	—	—	51,738
Total undeveloped.....	634,094	17,444	21,259	866,312
Total estimated proved reserves.....	1,448,254	31,593	44,429	1,904,386

(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 2011, the average of the first-day-of-the-month gas price was \$4.12 per Mcf, and the average of the first-day-of-the-month oil price was \$96.08 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 23 Mcf per barrel of oil and approximately 13 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2011).

As of December 31, 2011, Forest had estimated proved reserves of 1,904 Bcfe, an increase of 2% compared to 1,868 Bcfe of estimated proved reserves from continuing operations at December 31, 2010. Of the December 31, 2011 total, 1,853 Bcfe (97%) were in the United States and 52 Bcfe (3%) were in Italy. During 2011, we added 301 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2011 drilling activity in the Texas Panhandle and South Texas, with such additions partially offset by property sales of 21 Bcfe and negative revisions of 120 Bcfe, including 47 Bcfe related to proved undeveloped locations ("PUD") that were written off pursuant to the Securities and Exchange Commission's ("SEC") five year development limitation on PUDs.

As of December 31, 2011, proved undeveloped reserves were estimated to be 866 Bcfe, or 45% of estimated proved reserves, compared to 730 Bcfe, or 39% of estimated proved reserves from continuing operations as of December 31, 2010. The net increase of 136 Bcfe was primarily due to the recording of horizontal PUDs in the Texas Panhandle and South Texas. We invested \$182 million to convert 71 Bcfe of our December 31, 2010 PUD reserves to proved developed reserves during 2011. We have no material concentrations of PUDs in individual fields or countries that we expect to remain undeveloped for five years past the date they were initially disclosed as PUDs, except with respect to a concentration of reserves in Italy related to four natural gas wells (which make up all of the 52 Bcfe of proved reserves in Italy).

In 2007, we drilled, completed, and tested two natural gas wells in Italy. At December 31, 2007, we recorded proved developed reserves attributable to those two wells as well as proved undeveloped reserves attributable to two undrilled offset locations. Since 2007, we have been engaged with various governmental and jurisdictional agencies in a process to obtain approval of an environmental impact assessment ("EIA") and a production license needed to initiate production from the developed reserves, and to start full field development. The process has proceeded at a considerably slower pace than we anticipated and has still not reached a conclusion. At December 31, 2011, we determined to reclassify our proved developed reserves associated with the two wells already drilled and completed in Italy to the proved undeveloped category. At the present time, we anticipate obtaining approval of the EIA and production license during 2012. If we are successful in that respect, we would expect to initiate production in Italy in early 2015, following the construction of a needed desulfurization plant and pipeline. During the initial two years of production, the volumes that we may produce in Italy under the anticipated regulatory conditions will be limited to approximately 12 MMcf/day. This curtailment, coupled with the expected plant capacity, will likely cause us to delay drilling the two undeveloped locations until 2017.

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 Vice President, Corporate Engineering, 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 Vice President, Corporate Engineering, Michael Dern, has 34 years of experience in oil and gas exploration and production and has held this position at Forest since July 2011. Prior to that time, Mr. Dern held positions of increasing responsibility at Forest since joining the company in 2001, including most recently Reservoir Engineering Manager for the Eastern Region. Prior to joining Forest, Mr. Dern held various positions in reservoir engineering and corporate planning with Phillips Petroleum, Midcon Exploration, and Apache Corporation. Mr. Dern received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines.

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

Independent Audit of Reserves

We engage independent reserve engineers to audit a substantial portion of our reserves. Our audit procedures require the independent engineers to prepare their own estimates of proved reserves for fields comprising at least 80% of the aggregate net present value, discounted at 10% per annum ("NPV"), of our year-end proved reserves for each country in which proved reserves have been recorded. The fields selected for audit also must comprise at least 80% of Forest's fields based on the NPV of such fields and a minimum of 80% of the NPV added during the year through discoveries, extensions, and acquisitions. The procedures prohibit exclusions of any fields, or any part of a field, that comprises 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 SEC.

For the years ended December 31, 2011, 2010, and 2009, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2011, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 83% of our reserves by NPV as of December 31, 2011. 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 5% of DeGolyer and MacNaughton's aggregate estimate of proved reserves for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists, and has in excess of 37 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

The following table summarizes the number of wells drilled during 2011, 2010, and 2009 related to our continuing operations, 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, 2011, we had 21 gross (12 net) wells in progress in the United States. During 2011, we drilled a total of 127 gross (68 net) wells, of which 26 were classified as exploratory and 101 were classified as development. Our 2011 drilling program, which primarily consisted of horizontal wells, achieved a 97% success rate.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
United States:						
Productive	101	44	75	38	76	47
Non-productive ⁽¹⁾	—	—	5	4	6	4
Total development wells.....	101	44	80	42	82	51
Exploratory wells:						
United States:						
Productive	22	21	24	16	23	14
Non-productive ⁽¹⁾	4	3	5	4	—	—
Total.....	26	24	29	20	23	14
Italy:						
Non-productive ⁽¹⁾	—	—	—	—	1	1
Total.....	—	—	—	—	1	1
Total exploratory wells.....	26	24	29	20	24	15

(1) 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 Gas Wells and Acreage

Productive Wells

The following table summarizes our productive wells as of December 31, 2011, all of which are located in the United States and Italy. 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, 2011, Forest owned interests in 78 gross wells containing multiple completions.

	United States		Italy		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas.....	3,585	2,612	2	2	3,587	2,614
Oil.....	364	229	—	—	364	229
Total.....	3,949	2,841	2	2	3,951	2,843

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, 2011. A 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, 2011, approximately 2%, 1%, and 11% of our net undeveloped acreage in the United States was held under leases that will expire in 2012, 2013, and 2014, respectively, if not extended by exploration or production activities.

Location	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States ⁽¹⁾	683,167	430,397	530,082	336,889
South Africa ⁽²⁾	—	—	2,771,695	1,474,542
Italy	—	—	107,043	86,507
Total	<u>683,167</u>	<u>430,397</u>	<u>3,408,820</u>	<u>1,897,938</u>

(1) Concentrations of net acres in the United States as of December 31, 2011 include: 109,000 net acres in the Texas Panhandle; 125,000 net acres in East Texas / North Louisiana; 232,000 net acres in the South Texas (including 103,000 in the Eagle Ford Shale); 89,000 net acres in the Permian Basin in West Texas; and 72,000 net acres in the Uintah Basin in Utah.

(2) We applied to the South African government to convert one existing prospecting sublease (known as Block 2C) into an Exploration Right, and for a Production Right covering the geographic area of our other prospecting sublease (known as Block 2A). The Block 2A Production Right was granted in August 2009. The first term of this Production Right is for up to five years during which we, and our partners, are permitted to develop the local market for natural gas. Required work programs are minimal and full development remains contingent at our and our partners' option. The Block 2C Exploration Right conversion was executed in April 2010. It requires a work program of one exploration well during the initial three-year period, with additional work obligations expected in any further exploration periods. We continue to pursue commercial development of the Ibhubesi field discovery in South Africa, including continued efforts toward securing gas sales contracts.

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, 2011, 2010, and 2009 for continuing operations. Forest's Italian geographical area has not had any production and Forest does not have any fields that individually contain 15% or more of the Company's total estimated proved reserves.

	Year Ended December 31,		
	2011	2010	2009
Natural Gas:			
Production volumes (MMcf).....	88,497	101,346	116,029
Average sales price (per Mcf).....	\$ 3.71	\$ 3.99	\$ 3.33
Liquids:			
Oil and condensate:			
Production volumes (MBbls).....	2,491	2,357	3,397
Average sales price (per Bbl).....	\$ 96.22	\$ 76.08	\$ 56.87
Natural gas liquids:			
Production volumes (MBbls).....	3,154	3,589	3,012
Average sales price (per Bbl).....	\$ 42.91	\$ 34.54	\$ 25.17
Total liquids:			
Production volumes (MBbls).....	5,645	5,946	6,409
Average sales price (per Bbl).....	\$ 66.43	\$ 51.01	\$ 41.97
Total production volumes (MMcfe) ⁽¹⁾.....	122,367	137,022	154,483
Average sales price (per Mcfe).....	\$ 5.75	\$ 5.16	\$ 4.24
Production costs (per Mcfe):			
Lease operating expenses.....	\$.81	\$.67	\$.77
Transportation and processing costs.....	.11	.10	.08
Production costs excluding production and property taxes (per Mcfe).....	.92	.77	.86
Production and property taxes.....	.33	.32	.26
Total production costs (per Mcfe).....	\$ 1.25	\$ 1.09	\$ 1.12

(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 2011, the average of the first-day-of-the-month gas price was \$4.12 per Mcf, and the average of the first-day-of-the-month oil price was \$96.08 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 23 Mcf per barrel of oil and approximately 13 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2011).

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 16, 2012.

Competition

Forest encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil and gas, obtaining services and labor, and securing drilling rigs and other equipment necessary for drilling and completing wells. Our ability to increase reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on major development drilling programs, and acquire additional leases and prospects for future development and exploration. A large number of the companies that we compete with have substantially larger staffs and greater financial and operational resources than we have. Because of the nature of our oil and gas assets and management's experience in exploiting our reserves and acquiring properties, management believes that we effectively compete in our markets.

Industry Regulation

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

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

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

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

Environmental and Climate Change Regulation

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

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have

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

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

Hydraulic fracturing is an important process used in the completion of our oil and gas wells. The process involves the injection of water, sand, and chemicals under pressure into low-permeability formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Various state and local governments have implemented or are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, requirements for disclosure of chemical constituents, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For instance, in December 2011, the states of Texas and Colorado 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 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. In addition, Congress has considered legislation to regulation under the SDWA. If adopted, such legislation would establish an additional level of regulation and impose additional costs on our operations. See Part I, Item 1A—"Risk Factors—*We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations*" below.

Nearly half of the states in the U.S., either individually or through multi-state initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases ("GHGs"). Also, the Supreme Court held in *Massachusetts et al v. EPA* (2007) that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act, and subsequently in December 2009, the EPA determined that GHG emissions present an endangerment to public health and the environment because such emissions, according to the EPA, are contributing to warming of the earth's atmosphere and other climate changes. These findings allow the EPA to implement regulations that would restrict GHG emissions under existing provisions of the Clean Air Act. On November 8, 2010, the EPA finalized GHG reporting requirements for the petroleum and natural gas industries. Under this final rule, owners or operators of facilities that contain petroleum and natural gas systems, as defined by the rule, and emit 25,000 metric tons or more of GHGs per year per basin (expressed as carbon dioxide equivalents) will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators will collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, record keeping, and reporting defined in the final rule. For purposes of the rule, an onshore petroleum and natural gas production facility is generally defined as all petroleum and natural gas equipment associated with all petroleum or natural gas production wells and CO₂ enhanced oil recovery operations that are under common ownership or control, including leased, rented, and contracted activities, by an onshore petroleum and natural gas production owner or operator and that are located within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists. The rule is estimated to require reporting from approximately 2,800 facilities, covering 85% of the total GHG emissions from the U.S. petroleum and natural gas industries, including all of Forest's facilities, with modeling reporting beginning in late 2012 and actual data reporting beginning in 2013. We expect these new rules to result in increased compliance costs on our operations. In addition, these rules, and any other new rules and regulations addressing GHG emissions, could result in additional operating restrictions.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future. We have established internal guidelines

to be followed in order to comply with environmental laws and regulations in the United States and other relevant international jurisdictions. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Employees

As of December 31, 2011, we had 676 employees. None of our employees is currently represented by a union for collective bargaining purposes.

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. The definitions of proved developed reserves, proved reserves, and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X. The entire definitions of those terms can be viewed on the SEC's website at <http://www.sec.gov>.

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

Bcf. Billion cubic feet of natural gas.

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

Bbtu. One billion British Thermal Units.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

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

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

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

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

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

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

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

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

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

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

Mcf. Thousand cubic feet of natural gas.

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

MMBtu. One million British Thermal Units, a common energy measurement.

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. Natural gas liquids.

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 that are 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. 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 recovery to occur.

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.

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 each of the committees of our Board of Directors (including the charters of the Audit Committee, Compensation Committee, and Nominating and Corporate Governance Committee), and codes of ethics for our directors and employees entitled "Code of Business Conduct and Ethics" and "Proper Business Practices Policy," respectively.

Forward-Looking Statements

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

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

- estimates of our oil and natural gas reserves;
- estimates of our future oil and natural gas production, including estimates of any increases or decreases in our production;
- 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, 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 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, including the risks discussed below. 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.

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 76% of our estimated proved reserves at December 31, 2011 were natural gas, causing us to be particularly dependent on prices for natural gas.

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

- impairing our financial condition, liquidity, or ability to fund planned capital expenditures;
- limiting our access to sources of capital, such as equity and debt; or
- prohibiting us from developing our current properties, or from growing our asset base.

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

As of December 31, 2011, we had long-term indebtedness of \$1.7 billion, including \$105 million drawn under our bank

credit facility. The governing documents of our debt contain covenants and restrictions that require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness.

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 flow 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 and natural gas prices, and adverse developments in our business.

If our cash flow is not sufficient to service our debt and other obligations or to meet the financial covenants, we may be required to refinance the debt, sell assets, or sell shares of our stock—all on terms that we do not find attractive, if it can be done at all.

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

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

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 contained in this report 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 and natural gas 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, 2011, approximately 45% 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.

You should not assume that any present value of future net cash flows from our estimated proved reserves represents the market value of our oil and natural gas reserves.

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

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

exploration or acquisition, our proved reserves and production will decline over time.

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

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

A sizable portion of our acreage 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 for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, cash flow, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

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

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

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

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

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

We periodically enter into hedging agreements for a portion of our anticipated oil, natural gas, and NGL 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 had the hedge not been in place.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted by Congress is expected to, among other things, impose new requirements and oversight on derivatives transactions, including new clearing and margin requirements. While implementing regulations are yet to be completed by federal regulatory agencies, to the extent they are applicable to us or our derivatives counterparties, we may incur increased costs and cash collateral requirements that could affect our ability effectively to hedge risks associated with our business.

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

Our oil and natural gas operations are subject to various U.S. federal, state, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. Many of the laws and regulations to which our operations are subject

include those relating to the protection of the environment. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, present or future environmental laws and regulations.

We routinely utilize hydraulic fracturing, which is an important and common practice used to stimulate production of hydrocarbons from tight, or low-permeability formations. State oil and gas commissions typically regulate the process. However, several federal entities, including the EPA, have also recently asserted potential regulatory authority over hydraulic fracturing. Some states, such as Texas, have adopted, and some states, including others in which we operate, are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. 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.

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 Consolidated Financial Statements for a more complete discussion of credit risk with respect to our derivative instruments.

We may record impairments of our asset values, which could negatively affect our results of operations and net worth.

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon the twelve-month average oil and natural gas prices at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows, adjusted as required, from our oil and natural gas properties falls below the net book value of these properties, adjusted as required. Such write-downs are referred to as "ceiling test write-downs." We have in the past experienced ceiling test write-downs with respect to our oil and natural gas properties. Future non-cash ceiling test write-downs could negatively affect our results of operations and net worth. See Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments, and Assumptions—*Full Cost Method of Accounting.*"

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting unit exceeds the estimated fair value of that reporting unit, an impairment charge will occur, which would negatively impact our results of operations and net worth. See Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments, and Assumptions—*Goodwill.*"

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

In August 2007, we closed on the sale of our oil and gas assets in Alaska (the "Alaska Assets") to Pacific Energy Resources, Ltd. ("PERL"). In March 2009, PERL filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. PERL requested, and the bankruptcy court has approved, abandonment of PERL's interests in certain of the Alaska Assets. The remaining working interest owners in the Alaska Assets have made the assertion that, in its role as assignor of the Alaska Assets, Forest should be held liable for any contractual obligations of PERL with respect to the Alaska Assets, including obligations related to operating costs and for costs associated with the final plugging and decommissioning of wells and production facilities. For example, Forest has been joined as a defendant in a dispute over which companies should bear the cost of decommissioning and abandoning a platform and its associated wells, located in Cook Inlet, Alaska. See Part I, Item 3—"Legal Proceedings" for a discussion of material litigation involving the Alaska Assets.

Item 1B. Unresolved Staff Comments.

As of January 25, 2012, all SEC staff comments regarding our periodic or current reports that had been received prior to 180 days before December 31, 2011 had been resolved.

Item 2. Properties.

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

Item 3. Legal Proceedings.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities ("PERL"). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL "abandoned" its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field ("Trading Bay"). At the time of the abandonment of PERL's interests in Trading Bay, Union Oil Company of California ("Unocal") was the operator of those assets. On December 2, 2010, Unocal filed a lawsuit styled *Union Oil Company of California v. Forest Oil Corporation* in Anchorage District Court, Alaska. Forest has removed the case to federal district court in Anchorage, Alaska. In the lawsuit, the plaintiff complains about PERL's abandonment of Trading Bay and states that PERL has failed to pay approximately \$48 million in joint interest billings owed on those properties to date from the time PERL owned them. The plaintiff further claims that Forest is liable for PERL's share of all joint interest billings owed on Trading Bay, in arrears and in the future, because (1) Forest was the predecessor party to the contracts governing the operations at Trading Bay, (2) Unocal did not agree that, in conjunction with Forest's sale of its Alaska assets, Forest would be released of its obligations under the Trading Bay contracts, and (3) PERL has defaulted on the joint interest billings owed on Trading Bay since October 2008. As of December 31, 2011, Unocal sold its interest in the Trading Bay assets, including its claims against Forest, to Hilcorp Energy Company. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend to vigorously defend the action.

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.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 16, 2012.

Name	Age	Years with Forest	Office⁽¹⁾
H. Craig Clark	55	11	President and Chief Executive Officer, and a member of the Board of Directors since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions including Executive Vice President—U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache.
Michael N. Kennedy.....	37	11	Executive Vice President and Chief Financial Officer since December 2009. Mr. Kennedy joined Forest in February 2001. He served as Senior Financial Analyst until April 2003, at which time he became Manager of Investor Relations. Mr. Kennedy served in that role until November 2005 when he became Managing Director of Capital Markets and Treasurer and in April 2008 assumed the role of Vice President—Finance and Treasurer. Prior to joining Forest, Mr. Kennedy worked for Arthur Andersen as a member of its audit and business advisory practice.
J.C. Ridens.....	56	8	Executive Vice President and Chief Operating Officer since November 2007. Since joining Forest in April 2004, Mr. Ridens has served as Senior Vice President for the Gulf Region, the Southern Region and the Western Region. From 2001 to 2004, Mr. Ridens was employed by Cordillera Energy Partners, LLC, as Vice President of Operations and Exploitation. From 1996 to 2001, he served in various capacities at Apache Corporation.
Cecil N. Colwell.....	61	23	Senior Vice President, Worldwide Drilling since May 2004. Between 2000 and May 2004, Mr. Colwell served as our Vice President, Drilling, and from 1988 to 2000 he served as our Drilling Manager, Gulf Coast.
Cyrus D. Marter IV.....	48	10	Senior Vice President, General Counsel and Secretary since November 2007. Mr. Marter served as Vice President, General Counsel and Secretary from January 2005 to November 2007, as Associate General Counsel from October 2004 to January 2005, and as Senior Counsel from June 2002 until October 2004. Prior to joining Forest, Mr. Marter was a partner in the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Glen J. Mizenko	49	11	Senior Vice President, Eastern Region since June 2011. Mr. Mizenko joined Forest in January 2001 as Manager Corporate Development and New Ventures. In October 2003, he was promoted to the position of Director, Business Development. In May 2005, he was promoted to Vice President, Business Development, and in May 2007 was again promoted to Senior Vice President, Business Development and Corporate Engineering. Prior to joining Forest, Mr. Mizenko held various positions in reservoir engineering, reserves reporting, development planning, and operations management with Shell Oil, Benton Oil & Gas, and British Borneo Oil and Gas PLC.
Victor A. Wind.....	38	7	Senior Vice President, Chief Accounting Officer and Corporate Controller since December 2009. Mr. Wind previously served as Vice President, Chief Accounting Officer and Corporate Controller since May 2009. He joined Forest as Corporate Controller in January 2005. 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.
Ronald C. Nutt.....	54	5	Vice President, Southern Region since July 2007. Prior to joining Forest, from March 2007 to July 2007, Mr. Nutt worked for Constellation Energy Group, and from January 2003 to March 2007 at Scotia Waterous as Vice President, Engineering.

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

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 16, 2012, our Common Stock was held by 653 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape, as well as adjusted prices per share of the Common Stock that reflect the stock dividend distributed by Forest on September 30, 2011. There were no cash dividends declared on the Common Stock in 2010 or 2011. On February 16, 2012, the closing price of Forest Common Stock was \$14.40.

		Common Stock		Common Stock (As Adjusted) ⁽¹⁾	
		High	Low	High	Low
2010	First Quarter	\$ 30.08	\$ 22.61	\$ 21.35	\$ 16.05
	Second Quarter.....	32.81	22.85	23.29	16.22
	Third Quarter.....	31.89	24.83	22.64	17.63
	Fourth Quarter.....	39.32	29.69	27.91	21.08
2011	First Quarter	\$ 40.23	\$ 32.39	\$ 28.56	\$ 22.99
	Second Quarter.....	38.65	24.56	27.44	17.44
	Third Quarter.....	28.22	14.14	20.03	10.04
	Fourth Quarter.....	17.22	8.88	17.22	8.88

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

The prices shown in the "As Adjusted" column above for the first quarter of 2010 through the third quarter of 2011 have been adjusted to reflect the stock dividend paid on September 30, 2011. The ratio used for this historical price adjustment is .2901. This represents the ratio of (a) \$4.18 to (b) \$14.41, the average of the high and low intraday sales prices per share of Forest Common Stock on September 30, 2011.

Dividend Restrictions

Forest's present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest's Restated Certificate of Incorporation and Bylaws, (iii) the indentures concerning Forest's 8½% senior notes due 2014 and Forest's 7¼% senior notes due 2019, and (iv) Forest's bank credit facility dated as of June 30, 2011. The provisions in the indentures pertaining to these senior notes and in the bank credit facility limit our ability to make restricted payments, which include dividend payments. On March 2, 2006, Forest distributed a special stock dividend in connection with the spin-off of its offshore Gulf of Mexico operations and, as noted above, on September 30, 2011, Forest distributed a special stock dividend in connection with the spin-off of Lone Pine; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends. For further information regarding our equity securities, our ability to pay dividends on our Common Stock, and the spin-off of Lone Pine, see Notes 3 and 5 to the Consolidated Financial Statements.

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during the quarter ended December 31, 2011.

Issuer Purchases of Equity Securities

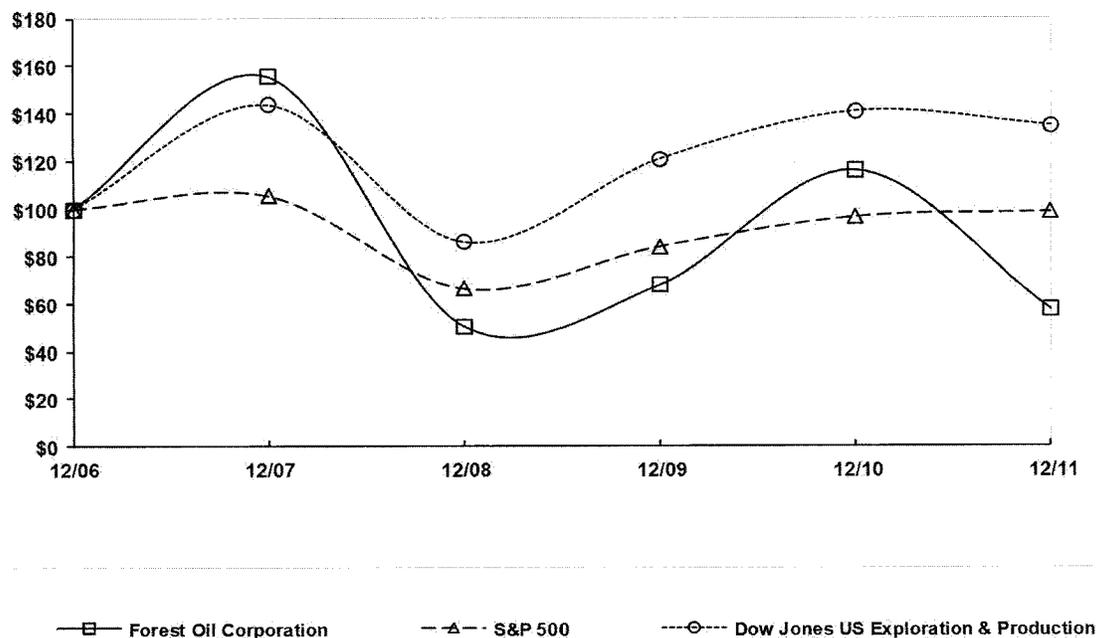
The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2011. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock and phantom stock units that are settled in shares. 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 2011.....	8,970	\$ 11.00	—	—
November 2011.....	2,523	15.16	—	—
December 2011	2,109	13.66	—	—
Fourth Quarter Total.....	<u>13,602</u>	12.19	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of \$100 on December 31, 2006 (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 12/31/06 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, 2011. This data should be read in conjunction with Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," below, and the Consolidated Financial Statements and Notes thereto contained elsewhere in this report. We have completed several oil and gas property acquisition and divestiture transactions that affect the comparability of the results for the years presented below. See Part I, Item 1—"Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements for more information on acquisitions and divestitures.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and NGL sales ⁽¹⁾	\$ 703,531	\$ 707,692	\$ 655,579	\$ 1,396,669	\$ 892,818
Net earnings (loss) from continuing operations	\$ 98,260	\$ 189,662	\$ (793,789)	\$ (1,081,446)	\$ 106,198
Net earnings (loss) from discontinued operations ⁽²⁾	44,569	37,859	(129,344)	55,123	63,108
Net earnings (loss)	\$ 142,829	\$ 227,521	\$ (923,133)	\$ (1,026,323)	\$ 169,306
Less: net earnings attributable to noncontrolling interest ⁽²⁾	4,987	—	—	—	—
Net earnings (loss) attributable to Forest Oil Corporation	\$ 137,842	\$ 227,521	\$ (923,133)	\$ (1,026,323)	\$ 169,306
Basic earnings (loss) per share: ⁽³⁾					
Earnings (loss) from continuing operations	\$.86	\$ 1.68	\$ (7.61)	\$ (12.07)	\$ 1.38
Earnings (loss) from discontinued operations	.35	.33	(1.24)	.61	.82
Basic earnings (loss) per common share	\$ 1.21	\$ 2.01	\$ (8.85)	\$ (11.46)	\$ 2.20
Diluted earnings (loss) per share: ⁽³⁾					
Earnings (loss) from continuing operations	\$.85	\$ 1.67	\$ (7.61)	\$ (12.07)	\$ 1.35
Earnings (loss) from discontinued operations	.34	.33	(1.24)	.61	.81
Diluted earnings (loss) per common share	\$ 1.19	\$ 2.00	\$ (8.85)	\$ (11.46)	\$ 2.16
Total assets ⁽¹⁾	\$ 3,381,151	\$ 3,070,197	\$ 3,169,054	\$ 4,555,903	\$ 4,903,834
Long-term debt ⁽¹⁾	\$ 1,693,044	\$ 1,869,372	\$ 2,022,514	\$ 2,641,246	\$ 1,639,911
Shareholders' equity	\$ 1,193,113	\$ 1,352,787	\$ 1,079,154	\$ 1,672,912	\$ 2,411,811
OPERATING DATA⁽¹⁾					
Annual production:					
Natural gas (MMcf)	88,497	101,346	116,029	118,120	82,963
Oil (MBbls)	2,491	2,357	3,397	3,778	4,504
NGLs (MBbls)	3,154	3,589	3,012	3,151	2,381
Average sales price:					
Natural gas (per Mcf)	\$ 3.71	\$ 3.99	\$ 3.33	\$ 7.54	\$ 5.95
Oil (per Bbl)	\$ 96.22	\$ 76.08	\$ 56.87	\$ 96.85	\$ 67.91
NGLs (per Bbl)	\$ 42.91	\$ 34.54	\$ 25.17	\$ 44.54	\$ 39.32

(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.

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

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

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

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, 2011, were approximately 1,904 Bcfe. At December 31, 2011, approximately 97% of our estimated proved reserves were in the United States. Having spun-off our Canadian operations on September 30, 2011, we currently conduct our operations in one reportable geographical segment - the United States. Our core operational areas are in the Texas Panhandle, the East Texas / North Louisiana area, and the Eagle Ford Shale in South Texas. See Item 1—"Business" for a discussion of our business strategy and core operational areas of focus.

In December 2010, we announced our intention to separate our Canadian operations through an initial public offering of up to 19.9% of the common stock of our then wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which would hold our ownership interests in our Canadian operations, followed by a distribution, or spin-off, of the remaining shares of Lone Pine held by us to our shareholders. The offering occurred in June 2011, whereby we retained approximately 82% of the outstanding shares of Lone Pine's common stock. Lone Pine used the net proceeds from the offering, along with borrowings under its credit facility, to pay us approximately \$29 million, as partial consideration for our contribution to Lone Pine of our interests in the Canadian operations, and to repay an intercompany note and intercompany advances and accrued interest of approximately \$401 million. The spin-off of our remaining shares of Lone Pine to our shareholders was completed on September 30, 2011. As a result of the spin-off, Lone Pine's results of operations are reported as discontinued operations in our Consolidated Statements of Operations for all periods presented.

2011 Highlights

Forest's 2011 highlights are as follows:

- Completed an initial public offering and the subsequent spin-off of Lone Pine to Forest shareholders. Each Forest shareholder of record on September 16, 2011 received approximately .6125 shares of Lone Pine stock for every share of Forest stock held.
- Drilled or participated in 127 gross (68 net) wells in the United States in 2011 including 68 gross (33 net) horizontal wells in the Texas Panhandle with 20 gross wells targeting two new oil zones and three additional liquids-rich gas intervals, bringing the total number of productive intervals to 11 in the Texas Panhandle.
- Continued the initial development of our acreage in the Eagle Ford Shale oil window with the drilling of 15 wells focusing on optimizing the development of the resource. This optimization included taking core samples, acquiring 3-D seismic, the utilization of micro-seismic during horizontal well completion, and testing different sections of the Eagle Ford Shale.
- Initiated the acquisition of undeveloped leaseholds in the Permian Basin in West Texas. As of February 21, 2012 we have acquired over 126,000 gross acres (114,500 net) in the area at an average cost of approximately \$1,300 per acre. The acreage position includes 51,500 net acres prospective for the Wolfcamp shale in Crockett County, Texas and 63,000 net acres prospective for the Wolfbone intervals in Pecos and Reeves Counties, Texas.

Recent Trends and 2012 Outlook

Beginning in the second half of 2008 and continuing throughout 2011, the United States and other industrialized countries experienced a significant economic slowdown. During the same time period, North American natural gas supply increased as a result of increased domestic unconventional natural gas development and associated natural gas from oil development. In the second half of 2008, oil and natural gas prices declined dramatically. While oil and NGL prices have steadily improved since the first quarter of 2009, North American natural gas prices have remained at low levels and declined further in late-2011 as a result of increased supply and weak domestic demand in the United States. We do not plan on natural

gas prices improving significantly in 2012. As a result, as we did in 2011, we plan to direct the majority of our exploration and development capital expenditures in 2012 to more liquids-rich prospects. See Item 1—"Business—Core Operational Areas" for a summary of our core operational areas of focus.

Results of Operations

The following table sets forth selected operating results for the years ended December 31, 2011, 2010, and 2009.

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands, Except per Mcfe and per Share Data)		
Oil, natural gas, and NGL sales from continuing operations	\$ 703,531	\$ 707,692	\$ 655,579
Realized equivalent sales price (per Mcfe)	5.75	5.16	4.24
Net earnings (loss) from continuing operations	98,260	189,662	(793,789)
Diluted earnings (loss) per common share from continuing operations..	.85	1.67	(7.61)
Adjusted EBITDA from continuing operations ⁽¹⁾	550,865	619,101	726,529

(1) In addition to reporting net earnings (loss) from continuing operations as defined under generally accepted accounting principles ("GAAP"), we also present Adjusted EBITDA from continuing operations, which is a non-GAAP performance measure. See "—Reconciliation of Non-GAAP Measure" at the end of this Item 7 for a reconciliation of Adjusted EBITDA from continuing operations to reported net earnings (loss) from continuing operations, which is the most directly comparable financial measure calculated and presented in accordance with GAAP.

Our net earnings (loss) from continuing operations and diluted earnings (loss) per share from continuing operations presented in the table above were primarily impacted by changes in oil, natural gas, and NGL production volumes and prices, changes in realized and unrealized derivative gains and, in 2009, a non-cash ceiling test write-down of \$1.4 billion. See below for further discussion of these items. Adjusted EBITDA from continuing operations, which excludes the effects of ceiling test write-downs and other non-cash items, was also primarily impacted by changes in oil, natural gas, and NGL production volumes and prices for the periods presented, as well as changes in realized derivative gains.

Management's analysis of the individual components of the changes in our annual results follows.

Oil and Natural Gas Volumes and Revenues

Oil, natural gas, and natural gas liquids ("NGL") sales volumes, revenues, and average sales prices from continuing operations for the years ended December 31, 2011, 2010, and 2009, are set forth in the table below.

	Year Ended December 31,		
	2011	2010	2009
Sales volumes:			
Natural gas (MMcfe)	88,497	101,346	116,029
Oil (MBbls)	2,491	2,357	3,397
NGL (MBbls)	3,154	3,589	3,012
Totals (MMcfe)	<u>122,367</u>	<u>137,022</u>	<u>154,483</u>
Revenues (In Thousands):			
Natural gas	\$ 328,510	\$ 404,415	\$ 386,581
Oil	239,695	179,312	193,185
NGL	135,326	123,965	75,813
Totals	<u>\$ 703,531</u>	<u>\$ 707,692</u>	<u>\$ 655,579</u>
Average sales price per unit:			
Natural gas (\$/Mcf)	\$ 3.71	\$ 3.99	\$ 3.33
Oil (\$/Bbl)	96.22	76.08	56.87
NGL (\$/Bbl)	42.91	34.54	25.17
Totals	<u>\$ 5.75</u>	<u>\$ 5.16</u>	<u>\$ 4.24</u>

Our reported oil, natural gas, and NGL sales volumes from continuing operations decreased 11% in 2011 compared to

2010 primarily due to a decrease in natural gas production, which resulted from our decision to reduce capital expenditures for dry gas wells in response to declining natural gas prices. In 2011, we redirected capital expenditures from dry gas well development towards liquids and oil-rich prospects, including the early-stage development of our Eagle Ford oil play and the acquisition of new leaseholds in the Permian Basin prospective for oil development. Oil and natural gas revenues were essentially flat between 2010 and 2011, primarily due to an increase in oil and NGL prices that was offset by a decrease in natural gas production and prices.

Our reported oil, natural gas, and NGL sales volumes from continuing operations decreased 11% in 2010 compared to 2009. The decrease was due to oil and gas property divestitures that occurred primarily in late 2009 partially offset by production increases attributable to new wells drilled in 2010. Oil and natural gas revenues in 2010 were \$708 million, an 8% increase as compared to \$656 million in 2009. Oil and natural gas revenues increased due to the 22% increase in the average realized sales price per Mcfe, partially offset by the decrease in sales volumes discussed above.

The revenues and average sales prices reflected in the table above exclude the effects of commodity derivative instruments since 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,		
	2011	2010	2009
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	\$ 99,158	\$ 92,394	\$ 119,472
Production and property taxes	40,632	43,656	40,147
Transportation and processing costs.....	13,728	13,242	12,855
Production expense	<u>\$ 153,518</u>	<u>\$ 149,292</u>	<u>\$ 172,474</u>
Production expense per Mcfe:			
Lease operating expenses	\$.81	\$.67	\$.77
Production and property taxes33	.32	.26
Transportation and processing costs.....	.11	.10	.08
Production expense per Mcfe	<u>\$ 1.25</u>	<u>\$ 1.09</u>	<u>\$ 1.12</u>

Lease Operating Expenses

Lease operating expenses in 2011 were \$99 million, or \$.81 per Mcfe, compared to \$92 million, or \$.67 per Mcfe, in 2010. The \$.14 per Mcfe increase in 2011 compared to 2010 was primarily due to an increase in water handling costs and an increase in the number of producing oil properties that have higher average per-unit operating costs. Lease operating expenses were \$92 million, or \$.67 per Mcfe, in 2010 compared to \$119 million, or \$.77 per Mcfe, in 2009. The decrease in total and per-unit lease operating expenses was primarily due to oil and gas property divestitures that occurred during late 2009. The properties divested had higher average per-unit operating costs as compared to the properties we retained.

Production and Property Taxes

Production and property taxes, which primarily consist of severance taxes paid on the value of the oil, natural gas, and NGLs sold, were 5.8%, 6.2%, and 6.1% of oil, natural gas, and NGL revenues for the years ended December 31, 2011, 2010, and 2009, respectively. Normal fluctuations occur in the percentage between periods based upon the approval of incentive tax credits in Texas, changes in tax rates, and changes in the assessed values of oil and gas properties and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were \$14 million, or \$.11 per Mcfe, in 2011, \$13 million, or \$.10 per Mcfe, in 2010, and \$13 million, or \$.08 per Mcfe, in 2009.

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,		
	2011	2010	2009
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs.....	\$ 35,706	\$ 31,475	\$ 27,801
Other general and administrative costs.....	75,792	76,018	78,983
General and administrative costs capitalized.....	(46,393)	(42,607)	(41,530)
General and administrative expense	<u>\$ 65,105</u>	<u>\$ 64,886</u>	<u>\$ 65,254</u>
General and administrative expense per Mcfe.....	<u>\$.53</u>	<u>\$.47</u>	<u>\$.42</u>

General and administrative expense was \$65 million in each of the years presented. Stock-based compensation costs and general and administrative costs capitalized under the full cost method of accounting increased in 2011 due to the recognition of \$12 million (\$7 million of expense, net of capitalized amounts) of costs in the third quarter of 2011 due to the spin-off of Lone Pine, which caused the forfeiture restrictions to lapse on a portion of each outstanding restricted stock award, thus requiring the immediate recognition of compensation cost. This increase in stock-based compensation costs was partially offset by a decrease in stock-based compensation costs due to a decline in our stock price in 2011. The percentage of general and administrative costs capitalized remained consistent between the three years presented, ranging between 39% and 42%.

Depreciation, Depletion, and Amortization

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense.....	\$ 219,684	\$ 187,973	\$ 247,158
Depreciation, depletion, and amortization expense per Mcfe	\$ 1.80	\$ 1.37	\$ 1.60

Depreciation, depletion, and amortization expense ("DD&A") increased \$.43 per Mcfe to \$1.80 in 2011 compared to \$1.37 in 2010. The increase in DD&A is primarily due to ceiling test write-downs recorded as of December 31, 2008 and March 31, 2009 as well as the sale of oil and gas assets in the fourth quarter of 2009, which together reduced our DD&A rate to \$1.25 in the first quarter of 2010. Our depletion rate has steadily increased thereafter as we have added proved oil and natural gas reserves to our depletable base at per-unit rates that have exceeded \$1.25 per Mcfe.

Ceiling Test Write-Down of Oil and Gas Properties

Pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting, Forest recorded a non-cash ceiling test write-down for its United States cost center totaling \$1.4 billion in the first quarter 2009. The write-down was a result of significant declines in oil and natural gas prices in the first quarter of 2009. See—"Critical Accounting Policies, Estimates, Judgments and Assumptions—Full Cost Method of Accounting."

Interest Expense

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Interest costs.....	\$ 160,014	\$ 161,139	\$ 173,258
Interest costs capitalized	(10,259)	(11,248)	(12,175)
Interest expense.....	<u>\$ 149,755</u>	<u>\$ 149,891</u>	<u>\$ 161,083</u>

Interest expense totaled \$150 million in both 2011 and 2010. In December 2011, we redeemed \$285 million of 8% senior notes using cash on hand and borrowings under our credit facility, with such redemption expected to result in lower total interest costs in 2012. Interest expense in 2010 totaled \$150 million compared to \$161 million in 2009. The \$11 million decrease in interest expense was primarily due to a decrease in average debt levels in 2010 compared to 2009. In January 2010, we redeemed \$150 million of 7¾% senior notes. In addition, in December 2009, we repaid all amounts outstanding under our credit facility. Interest costs capitalized relate to our investments in significant unproved acreage positions that are under development.

In order to effectively reduce the concentration of fixed-rate debt anticipated after the completion of our 2009 oil and gas property divestiture program and the related reduction in our credit facility balance, we entered into fixed-to-floating interest rate swaps in the first quarter of 2009 under which we have swapped, as of December 31, 2011, \$500 million in notional amount at an 8.5% fixed rate for an equal notional amount at a weighted-average interest rate equal to the 1-month LIBOR plus approximately 5.9%. We recognized realized gains under these interest rate swaps of \$11 million during each of the years ended December 31, 2011 and 2010 and \$7 million during the year ended December 31, 2009. These gains are recorded as realized gains on derivatives rather than as a reduction to interest expense since we have not elected to use hedge accounting. See Note 9 to the Consolidated Financial Statements for more information on our interest rate derivatives.

Realized and Unrealized Gains and Losses on Derivative Instruments

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Realized losses (gains) on derivatives, net:			
Oil.....	\$ 12,584	\$ 3,825	\$ (11,632)
Natural gas	(78,247)	(103,587)	(285,576)
NGL.....	28,128	—	—
Interest.....	(11,442)	(12,450)	(10,958)
Subtotal realized	<u>(48,977)</u>	<u>(112,212)</u>	<u>(308,166)</u>
Unrealized (gains) losses on derivatives, net:			
Oil.....	(10,297)	18,978	35,771
Natural gas	(22,931)	(47,078)	139,728
NGL.....	(4,314)	9,710	—
Interest.....	(1,545)	(19,530)	519
Subtotal unrealized	<u>(39,087)</u>	<u>(37,920)</u>	<u>176,018</u>
Realized and unrealized gains on derivatives, net.....	<u>\$ (88,064)</u>	<u>\$ (150,132)</u>	<u>\$ (132,148)</u>

Other, Net

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Accretion of asset retirement obligations	\$ 6,082	\$ 6,158	\$ 7,302
Legal proceeding settlement	6,500	—	—
Gain on debt extinguishment, net	—	(4,576)	—
Other, net	4,582	5,757	18,824
	<u>\$ 17,164</u>	<u>\$ 7,339</u>	<u>\$ 26,126</u>

Accretion of Asset Retirement Obligations

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

Legal Proceeding Settlement

During the second quarter of 2011, we settled litigation relating to the 2007 sale of our Alaska assets to Pacific Energy Resources, Ltd. ("PERL"), which included claims in excess of \$250 million. PERL and the other plaintiffs released us from all claims and agreed to dismiss the complaint against us in exchange for a \$7 million payment from us.

Gain on Debt Extinguishment

The net gain on debt extinguishment for the year ended December 31, 2010 includes the net gain related to the January 2010 redemption of our \$150 million 7¾% senior notes due 2014 at 101.292% of par. A net gain was recognized due to the write-off, at the time the notes were redeemed, of unamortized deferred gains resulting from the previous termination of interest rate swaps related to these notes. This gain was partially offset by the \$2 million redemption premium paid to redeem the notes. See Note 3 to the Consolidated Financial Statements for more information on our debt.

Income Tax

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands, Except Percentages)		
Current income tax	\$ 30,141	\$ (13,901)	\$ 70,815
Deferred income tax	58,994	123,671	(537,416)
Total income tax	<u>\$ 89,135</u>	<u>\$ 109,770</u>	<u>\$ (466,601)</u>
Effective income tax rate	48%	37%	37%

Our effective income tax rate generally approximates 37% to 38%. Our effective income tax rate was 48%, 37%, and 37% for the years ended December 31, 2011, 2010, and 2009, respectively. Our effective income tax rate was 48% for the year ended December 31, 2011 due to the Canadian dividend tax of \$29 million that was incurred on a stock dividend declared and paid by our former Canadian subsidiary, Lone Pine Resources Canada Ltd. ("LPR Canada"), to Forest, as parent, immediately before Forest's contribution of LPR Canada to Lone Pine in conjunction with Lone Pine's initial public offering. Without the \$29 million dividend tax, our effective income tax rate would have been 38% in 2011. See Note 4 to the Consolidated Financial Statements for a reconciliation of income tax computed by applying the United States federal statutory income tax rates for each period presented.

Discontinued Operations

The results of operations of Lone Pine are presented as discontinued operations in our Consolidated Statements of

Operations due to the spin-off of Lone Pine on September 30, 2011, with prior periods' results recast to conform with the discontinued operations presentation. Earnings from discontinued operations was negatively impacted by a ceiling test write-down in the Canadian cost center of \$199 million during 2009. See Note 13 to the Consolidated Financial Statements for more information regarding the components of 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 NGLs directly impact our level of cash flow generated from operations. Natural gas accounted for approximately 72% of our total production in 2011 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 price for oil and NGLs. 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 16, 2012, we had hedged, via commodity swaps, approximately 67 Bcfe of our total projected 2012 production and approximately 29 Bcf of our total projected 2013 production, excluding outstanding commodity swaptions and put options. This level of hedging will provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2012. 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 16, 2012, all of our derivative instrument counterparties are lenders, or affiliates of lenders, under our credit facility, with the exception of one counterparty. See Part II, Item 7A—"Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk," below for more information on our derivative contracts including commodity swaptions and put options.

The other primary source of liquidity is our credit facility, which had a borrowing base of \$1.25 billion as of December 31, 2011. This facility is used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facility is secured by a portion of our assets, with the facility maturing in June 2016. See—"Bank Credit Facility" below for further details. We had \$105 million and \$140 million drawn on our credit facility as of December 31, 2011 and January 31, 2012, respectively.

The public and private capital markets have served as our primary source of financing to fund large acquisitions and other exceptional transactions. In the past, we have issued debt and equity in both the public and private capital markets. For example, in February 2009, we issued \$600 million principal amount of 8½% senior notes due 2014 in a private offering for net proceeds of \$560 million, and in May 2009, we issued approximately 14 million shares of common stock for net proceeds of \$256 million. 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.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, during 2011, 2010, and 2009, we sold certain assets for approximately \$121 million, \$139 million, and \$933 million, respectively, with a portion of these proceeds used to pay off the outstanding balance under our credit facility in 2009 and redeem our 7¾% senior notes due 2014 in January 2010.

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

Bank Credit Facility

On June 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the "Credit Facility") with a syndicate of banks led by JPMorgan Chase Bank, N.A., consisting of a \$1.5 billion credit facility maturing in June 2016.

Subject to the agreement of us and the applicable lenders, the size of the Credit Facility may be increased by \$300 million, to a total of \$1.8 billion.

Our availability under the Credit Facility is governed by a borrowing base. As of December 31, 2011, the borrowing base under the Credit Facility was \$1.25 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of our oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. 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. The borrowing base was reaffirmed at \$1.25 billion in October 2011 and the next scheduled redetermination of the borrowing base will occur on or about May 1, 2012.

The borrowing base is also subject to change in the event (i) we or our Restricted Subsidiaries 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 then-existing senior notes, or (ii) we sell oil and natural gas properties included in the borrowing base having a fair market value in excess of 10% of the borrowing base then in effect. If the borrowing base is reduced to a level that is below our level of borrowing under the Credit Facility, we would be required to repay indebtedness in excess of the borrowing base in order to cover the deficiency.

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 $\frac{1}{2}$ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by us) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or
- (ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 basis points, depending on borrowing base utilization.

The Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also includes a financial covenant. The Credit Facility provides that we will not permit our ratio of total debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.50 to 1.00 at any time.

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

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 and our U.S. subsidiaries' estimated proved oil and gas properties and related assets. We are required to pledge, and have pledged, the stock of certain subsidiaries to secure the Credit Facility. If our corporate credit rating by Moody's and S&P meet pre-established levels, the security requirements would cease to apply and, at our request, the banks would release their liens and security interest on our properties.

Of the \$1.5 billion total nominal amount under the Credit Facility, JPMorgan and eleven other banks hold approximately 68% of the total commitments, with each of these twelve lenders holding an equal share. 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.

Prior to entering into the Credit Facility, the previous combined credit facility, the Second Amended and Restated Credit Agreement dated as of June 6, 2007, consisting of U.S. and Canadian facilities (the "Combined Credit Facility") was amended on May 25, 2011, to, among other things, remove any collateral owned by Lone Pine or any of its subsidiaries from the collateral securing the U.S. portion of the Combined Credit Facility, terminate the previous Canadian portion of the Combined Credit Facility, terminate various guaranties securing the Canadian portion of the Combined Credit Facility, release collateral

securing the Canadian portion of the Combined Credit Facility, and terminate certain liens and mortgages securing the Canadian portion of the Combined Credit Facility.

At December 31, 2011, there were outstanding borrowings of \$105 million under the Credit Facility at a weighted average interest rate of 2.1% and we had used the Credit Facility for \$2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of \$1.1 billion. At January 31, 2012, there were outstanding borrowings of \$140 million under the Credit Facility at a weighted average interest rate of 1.8% and we had used the Credit Facility for \$2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of \$1.1 billion.

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 Investor Services and Standard & Poor's Rating 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 rating at the time any such financing activities are conducted.

Historical Cash Flow

Net cash provided by operating activities of continuing operations, net cash (used) provided by investing activities of continuing operations, and net cash used by financing activities of continuing operations for the years ended December 31, 2011, 2010, and 2009 were as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Net cash provided by operating activities of continuing operations	\$ 398,097	\$ 446,725	\$ 536,374
Net cash (used) provided by investing activities of continuing operations.....	(759,730)	(423,054)	356,889
Net cash used by financing activities of continuing operations	(173,305)	(142,211)	(401,199)

Net cash provided by operating activities of continuing operations is generally primarily affected by sales volumes and commodity prices net of the effects of settlements of our derivative contracts and changes in working capital. The decrease in net cash provided by operating activities of continuing operations of \$49 million in 2011 as compared to 2010 was primarily due to (i) lower sales volumes that was offset by higher prices that resulted in little change in revenues; (ii) lower realized gains on commodity derivative instruments of \$62 million; and, (iii) an increase in current income tax expense of \$44 million. These decreases were partially offset by a decreased investment in net operating assets (i.e., working capital) of \$69 million. The decrease in net cash provided by operating activities of continuing operations of \$90 million in 2010 as compared to 2009 was primarily due to (i) lower realized gains on commodity derivative instruments of \$197 million and (ii) an increased investment in net operating assets (i.e., working capital) of \$80 million. These decreases were partially offset by (i) a decrease in current income tax expense of \$85 million; (ii) increased revenue of \$52 million due to increased commodity prices offsetting decreased sales volumes; and, (iii) decreased production expense of \$23 million.

The components of net cash (used) provided by investing activities of continuing operations for the years ended December 31, 2011, 2010, and 2009 were as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Exploration, development, acquisition, and leasehold costs ⁽¹⁾	\$ (873,877)	\$ (556,988)	\$ (545,357)
Proceeds from sales of assets	121,115	139,077	933,492
Other fixed asset costs	(6,968)	(5,143)	(31,274)
Other, net.....	—	—	28
Net cash (used) provided by investing activities of continuing operations.....	<u>\$ (759,730)</u>	<u>\$ (423,054)</u>	<u>\$ 356,889</u>

(1) Cash paid for exploration, development, and 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 payment is made as well as non-cash capital expenditures such as capitalized stock-based compensation costs.

Net cash (used) provided by investing activities of continuing operations is primarily comprised of expenditures for the acquisition, exploration, and development of oil and gas properties net of proceeds from the dispositions of oil and gas properties and other capital assets. The \$337 million increase in cash used for investing activities of continuing operations between 2011 and 2010 was primarily due to an increase in leasehold acquisition costs in 2011 as well as capital expenditures incurred in 2011 associated with our Eagle Ford Shale and Wolfcamp development where non-recurring activities such as core sampling, acquiring 3-D seismic, and drilling micro-seismic wells were performed. The \$780 million fluctuation in investing cash flows of continuing operations between 2010 and 2009 was primarily due to a \$794 million decrease in proceeds from the sales of oil and gas properties due to the completion of the majority of our property divestiture program in 2009.

Net cash used by financing activities of continuing operations of \$173 million in 2011 primarily included the redemption of the 8% senior notes in December 2011 for \$285 million, partially offset by net credit facility borrowings of \$105 million. Net cash used by financing activities of continuing operations of \$142 million in 2010 primarily included the redemption of the 7¾% senior notes for \$152 million. Net cash used by financing activities of continuing operations of \$401 million in 2009 primarily included net repayments of bank borrowings of \$1.2 billion, partially offset by net proceeds of \$560 million for the issuance of 8½% senior notes due 2014 and net proceeds of \$256 million for the issuance of common stock.

Capital Expenditures

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Property Acquisitions:			
Proved properties	\$ —	\$ 5,823	\$ —
Unproved properties including leasehold acquisition costs	204,537	64,593	45,230
	<u>204,537</u>	<u>70,416</u>	<u>45,230</u>
Exploration:			
Direct costs.....	272,422	172,746	106,586
Overhead capitalized.....	20,964	22,241	15,689
	<u>293,386</u>	<u>194,987</u>	<u>122,275</u>
Development:			
Direct costs.....	392,406	299,461	314,504
Overhead capitalized.....	25,429	20,366	25,841
	<u>417,835</u>	<u>319,827</u>	<u>340,345</u>
Total capital expenditures ⁽¹⁾	<u>\$ 915,758</u>	<u>\$ 585,230</u>	<u>\$ 507,850</u>

(1) Total capital expenditures include cash expenditures, accrued expenditures, and non-cash capital expenditures including stock-based compensation capitalized under the full cost method of accounting. Total capital expenditures also include changes in estimated discounted asset retirement obligations of \$3 million, \$(1) million, and \$1 million recorded during the years ended December 31, 2011, 2010, and 2009, respectively.

We have established an exploration and development capital budget of \$480 million to \$520 million for 2012 and plan to focus heavily on oil and other liquids-based drilling opportunities within our concentrated asset base. Primary factors impacting the level of our capital expenditures include crude 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.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011:

	2012	2013	2014	2015	2016	After 2016	Total
	(In Thousands)						
Bank debt ⁽¹⁾	\$ 6,230	\$ 6,230	\$ 6,230	\$ 6,230	\$ 108,115	\$ —	\$ 133,035
Senior notes ⁽²⁾	123,501	123,512	678,875	72,500	72,500	1,178,229	2,249,117
Derivative liabilities ⁽³⁾	28,944	—	—	—	—	—	28,944
Other liabilities ⁽⁴⁾	6,114	11,868	9,842	9,478	14,124	72,763	124,189
Operating leases ⁽⁵⁾	29,728	29,010	24,038	17,263	16,917	19,836	136,792
Unconditional purchase obligations ⁽⁶⁾	4,333	851	—	—	—	—	5,184
Total contractual obligations.....	<u>\$ 198,850</u>	<u>\$ 171,471</u>	<u>\$ 718,985</u>	<u>\$ 105,471</u>	<u>\$ 211,656</u>	<u>\$ 1,270,828</u>	<u>\$ 2,677,261</u>

- (1) Bank debt consists of the \$105 million outstanding balance under our credit facility as of December 31, 2011 and the anticipated interest payments on that balance, as well as commitment and letter of credit fees based on the \$1.25 billion borrowing base and \$2 million in outstanding letters of credit as of December 31, 2011, assuming all such balances remain until the maturity of the credit facility.
- (2) Senior notes consist of the principal obligations on our senior notes and senior subordinated notes and anticipated interest payments due on each.
- (3) Derivative liabilities represent the fair value of our derivative liabilities as of December 31, 2011. 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 their timings can be precisely determined in advance. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.
- (5) Operating leases consist of leases for drilling rigs, compressors, and office facilities and equipment.
- (6) Unconditional purchase obligations consist primarily of drilling commitments, throughput obligations, and seismic purchase obligations.

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 maximum commitment of future delay lease rental payments, through 2019, totaled approximately \$11 million as of December 31, 2011.

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, 2011, 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. As of February 16, 2012, we had obtained 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 \$15 million. See Part I, Item 1—"Business—Industry Regulation" for further information.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

Full Cost Method of Accounting

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

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

Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Changes in estimates of reserves or future development costs are accounted for in the current quarter and prospectively in the depletion calculations. We have historically updated our quarterly depletion calculations with our quarter-end reserves estimates. Based on this accounting policy, our December 31, 2011 reserves estimates were used for our fourth quarter 2011 depletion calculation. See Part I, Item 1, "Business—Reserves" and Note 15 to the Consolidated Financial Statements for a more complete discussion of our estimated proved reserves as of December 31, 2011.

Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter for each cost center. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved oil and natural gas reserves. This ceiling is compared to the net book value of the oil and gas properties reduced by any related net deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash write-down is required. Forest recorded a \$1.4 billion non-cash ceiling test write-down in the first quarter of 2009 as a result of significant declines in oil and natural gas prices at that time. We have not incurred a ceiling test write-down since March 31, 2009 through December 31, 2011. Our ceiling test calculations are based on the twelve-month average natural gas and oil prices since December 31, 2009 in accordance with SEC regulations.

In countries or areas where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs, and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. If exploration activities result in the establishment of proved reserves, amounts are reclassified as proved properties and become subject to depreciation, depletion, and amortization, and the application of the ceiling limitation. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to 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.

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 if events or circumstances change between annual tests, indicating a possible impairment.

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

To determine the fair value of our reporting unit, we use a discounted cash flow model to value our total estimated reserves, which include proved, probable, and possible reserves. This approach relies on significant judgments about the quantity of reserves, the timing of the expected production, the pricing that will be in effect at the time of production, and the appropriate discount rates to be used. Our discount rate assumptions are based on an assessment of Forest's weighted average cost of capital.

We did not record an impairment charge as a result of our goodwill impairment test in the second quarter of 2011 and no events or circumstances have occurred since then that have indicated a possible impairment, requiring an updated test. Due to the significant judgments that go into the 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 gas that geoscience and engineering data demonstrate, with reasonable certainty, to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods, and governmental regulations, prior to the time at which contracts providing the right to operate expire. 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 prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent uncertainty in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a "ceiling test" limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures included in Note 15 to the Consolidated Financial Statements.

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

Fair Value of Derivative Instruments

We use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and option-pricing models for valuing our collars, swaptions, puts, and calls. 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 "Realized and unrealized gains or losses on derivative instruments, net" in our Consolidated Statements of Operations.

Due to the volatility of oil and natural gas prices and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Item 7A—"Quantitative and Qualitative Disclosures about Market

Risk" for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

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 on income tax assets and liabilities of a change in tax rates 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, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon whether future book income is sufficient to reverse existing temporary differences that give rise to deferred tax assets, as well as whether future taxable income is sufficient to utilize net operating loss and credit carryforwards. Assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive.

Negative evidence considered by management primarily included book losses incurred in 2008 and 2009 that were driven entirely from ceiling test write-downs, which are not fair value based measurements. Under the full cost method of accounting, we recorded \$3.7 billion in ceiling test write-downs of the book value of our U.S. oil and gas properties in 2008 and 2009, which substantially reduced the book value of our oil and gas properties, resulting in the recognition of a net deferred tax asset. However, the write-downs also substantially reduced our prospective depletion rate at the time the write-downs occurred, making future book income, and therefore the reversal of book to tax temporary differences, more likely than would be the case had these ceiling test write-downs not occurred. Positive evidence considered by management included book income in 2010 and 2011, forecasted book income over a reasonable period of time, and the utilization of substantially all of our then existing net operating loss ("NOL") carryforwards in 2009 due primarily to a substantial tax gain associated with the sale of nearly \$1 billion in U.S. oil and gas assets. Based upon the evaluation of what management determined to be relevant evidence, we have not recorded a valuation allowance against our U.S. deferred tax assets as of December 31, 2011. See Note 4 to the Consolidated Financial Statements. The primary evidence utilized to determine that it is more likely than not that our deferred tax assets will be realized was management's expectation of future book income over the next several years, the expectation that we will utilize our net operating losses as of December 31, 2011 by carrying them back to 2009, and the fact that AMT credit carryforwards do not expire.

Asset Retirement Obligations

Forest has obligations to remove tangible equipment and restore locations at the end of the oil and gas production operations. Estimating the future restoration and removal costs, or asset retirement obligations, is difficult and requires management 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 asset retirement obligations ("ARO") are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, which is included in "Other, net" in the Consolidated Statements of Operations.

Impact of Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-05, *Comprehensive Income, Presentation of Comprehensive Income* ("ASU 2011-05"), which provides amendments that will result in more converged guidance on how comprehensive income is presented under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards ("IFRS"). ASU 2011-05 requires an entity to present items of net income, items of other comprehensive income, and total comprehensive income either in a single continuous statement or in two separate consecutive statements and eliminates the option to report other comprehensive income and its components in the statement of shareholders' equity. ASU 2011-05 also requires entities to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income. In December 2011, the FASB issued Accounting Standards Update No. 2011-12, *Comprehensive Income, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated*

Other Comprehensive Income in Accounting Standards Update No. 2011-05 (“ASU 2011-12”), which indefinitely defers the requirements in ASU 2011-05 to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income. Both ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011, and should be applied retrospectively. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations, but will require us to present the statements of comprehensive income separately from our statements of shareholders' equity, as these statements are currently presented on a combined basis.

In June 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (“ASU 2011-04”), which amends the current U.S. GAAP fair value measurement and disclosure guidance, to converge U.S. GAAP and IFRS requirements for measuring amounts at fair value as well as disclosures about these measurements. Many of the amendments clarify existing concepts and are not expected to result in significant changes to how companies apply the fair value principles. This authoritative guidance is effective for interim and annual periods beginning after December 15, 2011. We are currently evaluating the impact that the adoption of this authoritative guidance will have on our fair value measurements and disclosures.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, *Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment* (“ASU 2011-08”), which permits entities to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount to determine whether it is necessary to perform the two-step goodwill impairment test. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, it is required to perform the first step of the two-step impairment test, which may then lead an entity to performing the second step as well. Entities have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to the first step of the two-step impairment test. This authoritative guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this authoritative accounting guidance may change the methodology that we use to test our goodwill for impairment depending on the events or circumstances at the time the test is performed.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities* (“ASU 2011-11”), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparison between U.S. GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing U.S. GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations, but will require us to make enhanced disclosures regarding our derivative instruments.

Reconciliation of Non-GAAP Measure

Adjusted EBITDA

In addition to reporting net earnings from continuing operations as defined under GAAP, we also present adjusted earnings from continuing operations before interest, income taxes, depreciation, depletion, and amortization (“Adjusted EBITDA”), which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings from continuing operations before interest expense, income taxes, depreciation, depletion, and amortization, as well as other non-cash operating items such as unrealized gains and losses on derivative instruments and accretion of asset retirement obligations and other items presented in the table below. Adjusted EBITDA does not represent, and should not be considered an alternative to, GAAP measurements, such as net earnings 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 its business, including in preparing its 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 from continuing operations and revenues to measure operating performance. The following table provides a reconciliation of net earnings from continuing operations, the most directly comparable GAAP measure, to Adjusted EBITDA for the periods presented.

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Net earnings (loss) from continuing operations.....	\$ 98,260	\$ 189,662	\$ (793,789)
Income tax expense (benefit).....	89,135	109,770	(466,601)
Unrealized (gains) losses on derivative instruments, net.....	(39,087)	(37,920)	176,018
Unrealized losses on other investments.....	—	—	2,327
Interest expense.....	149,755	149,891	161,083
Legal proceeding settlement.....	6,500	—	—
Gain on debt extinguishment, net.....	—	(4,576)	—
Accretion of asset retirement obligations.....	6,082	6,158	7,302
Ceiling test write-down of oil and gas properties.....	—	—	1,376,822
Depreciation, depletion, and amortization.....	219,684	187,973	247,158
Stock-based compensation.....	20,536	18,143	16,209
Adjusted EBITDA from continuing operations.....	<u>\$ 550,865</u>	<u>\$ 619,101</u>	<u>\$ 726,529</u>

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

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower than the fixed price. If the index price is higher, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2011, we had entered into the following swaps:

Swap Term	Commodity Swaps								
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)			NGLs (OPIS Refined Products)		
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Hedged Price per Bbl	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2012 ⁽¹⁾ ...	105	\$ 5.30	\$ 78,145	—	\$ —	\$ —	2,000	\$ 45.22	\$ (5,396)
January 2012 - June 2012	—	—	—	5,000	98.24	(901)	—	—	—
July 2012 - December 2012	—	—	—	4,500	97.26	(910)	—	—	—

(1) During the fourth quarter, we entered into derivative agreements for the period April 2012 - December 2012 subjecting 50 Bbtu per day of the 2012 gas swaps to a written put of \$3.53 and a \$4.00 to \$4.50 call spread whereby we receive \$5.30 except as follows: we receive (i) NYMEX HH plus \$1.77 when NYMEX HH is below \$3.53; (ii) \$5.30 plus the value of the call spread when NYMEX HH is between \$4.00 and \$4.50; and (iii) \$5.80 when NYMEX HH is \$4.50 or above. The fair value of these derivative agreements as of December 31, 2011 was a liability of \$5.8 million.

Commodity Options

In connection with several natural gas swaps entered into, we granted option instruments to the natural gas swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas swaps. The table below sets forth the outstanding options as of December 31, 2011 (as of February 16, 2012, none of the swaptions in the table have been exercised by the counterparties).

Commodity Options					
Instrument	Option Expiration	Underlying Swap Term	Underlying Swap Barrels Per Day	Oil (NYMEX WTI)	
				Underlying Swap Hedged Price per Bbl	Fair Value (In Thousands)
Oil Swaptions....	June 2012	July - December 2012	500	\$ 107.10	\$ (498)
Oil Swaptions....	December 2012	Calendar 2013	5,000	105.00	(14,098)

The estimated fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2011 was a net asset of approximately \$51 million.

Due to the volatility of oil, natural gas, and NGL prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. For example, a hypothetical 10% increase in the forward oil, natural gas, and NGL prices used to calculate the fair values of our commodity derivative instruments at December 31, 2011 would decrease the net fair value of our commodity derivative instruments at December 31, 2011 by approximately \$39 million to a net asset of \$12 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, 2011 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, 2011

Subsequent to December 31, 2011, through February 16, 2012, we entered into the following derivative agreements:

Swap Term	Commodity Swaps	
	Natural Gas (NYMEX HH)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu
April 2012 - December 2012 ⁽¹⁾	50	\$ 3.23
Calendar 2013 ⁽²⁾	80	4.02

(1) In connection with entering into these natural gas swaps with premium hedged prices, we granted oil puts to the counterparties, giving the counterparties the option to put 5,000 barrels per day to us at \$75.00 per barrel on a monthly basis during April 2012 - December 2012.

(2) In connection with entering into these natural gas swaps with premium hedged prices, we granted some of the counterparties with the option to enter into oil swaps with us for Calendar 2014 covering 3,000 barrels per day at a weighted average hedged price per barrel of \$109.67, with such options expiring in December 2013, and granted the other counterparties with the option to enter into natural gas swaps with us for Calendar 2013 covering 20 Bbtu per day at a weighted average hedged price per MMBtu of \$4.02, with such options expiring in December 2012.

Interest Rate Risk

We periodically enter into interest rate derivative agreements in an attempt to manage the mix of fixed and floating interest rates within our debt portfolio. As of December 31, 2011, we had entered into the following fixed-to-floating interest rate swaps:

Remaining Swap Term	Interest Rate Swaps			
	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate	Fair Value (In Thousands)
January 2012 - February 2014..	\$ 500,000	1 month LIBOR + 5.89%	8.50%	\$ 20,556

The estimated fair value of all our interest rate derivative instruments based on various inputs, including published forward rates, at December 31, 2011 was an asset of approximately \$21 million.

Due to the volatility of interest rates, the estimated fair values of our interest rate derivative instruments are subject to

fluctuations from period to period. For example, a hypothetical 10% increase in the forward 1-month LIBOR interest rates used to calculate the fair values of our interest rate derivative instruments at December 31, 2011 would decrease the net fair value of our interest rate derivative instruments at December 31, 2011 by approximately \$1 million to an asset of \$20 million. Actual gains or losses recognized related to our interest rate derivative instruments will likely differ from those estimated at December 31, 2011 and will depend exclusively on the future 1-month LIBOR interest rates.

Derivative Fair Value Reconciliation

The table below sets forth the changes that occurred in the fair values of our derivative contracts during the year ended December 31, 2011, beginning with the fair value of our derivative contracts on December 31, 2010. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Due to the volatility of oil, natural gas, and NGL prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. Actual gains and losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2011 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, 2010.....	\$ 13,002	\$ 19,011	\$ 32,013
Net increase in fair value.....	75,076	12,987	88,063
Net contract gains recognized	(37,535)	(11,442)	(48,977)
As of December 31, 2011.....	<u>\$ 50,543</u>	<u>\$ 20,556</u>	<u>\$ 71,099</u>

Interest Rates on Borrowings

The following table presents principal amounts and related interest rates by year of maturity for Forest's debt obligations at December 31, 2011:

	2013	2014	2016	2019	Total
	(Dollar Amounts in Thousands)				
Bank credit facility:					
Variable rate.....	\$ —	\$ —	\$ 105,000	\$ —	\$ 105,000
Average interest rate ⁽¹⁾	—	—	2.09%	—	2.09%
Senior notes:					
Principal	\$ 12	\$ 600,000	\$ —	\$ 1,000,000	\$ 1,600,012
Fixed interest rate.....	7.00%	8.50%	—	7.25%	7.72%
Effective interest rate ⁽²⁾	7.49%	9.47%	—	7.24%	8.08%

(1) As of December 31, 2011.

(2) The effective interest rates on the senior notes differ from the fixed interest rates due to the amortization of related discounts or premiums on the notes.

Foreign Currency Exchange Rate Risk

We conduct business in Italy and South Africa, and thus are subject to foreign currency exchange rate risk on cash flows related primarily to expenses and investing transactions. We have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. Expenditures incurred relative to the foreign concessions held by Forest 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 and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. 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 and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 21, 2012

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

	December 31,	
	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 3,012	\$ 217,569
Accounts receivable	79,089	102,325
Derivative instruments	89,621	60,182
Other current assets	38,950	51,465
Current assets of discontinued operations	—	50,142
Total current assets	210,672	481,683
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of \$6,901,997 and \$6,688,012	1,923,145	1,370,864
Unproved	675,995	646,264
Net oil and gas properties	2,599,140	2,017,128
Other property and equipment, net of accumulated depreciation and amortization of \$47,989 and \$42,432	51,976	53,145
Net property and equipment	2,651,116	2,070,273
Deferred income taxes	231,116	284,021
Goodwill	239,420	239,420
Derivative instruments	10,422	8,244
Other assets	38,405	36,698
Long-term assets of discontinued operations	—	665,049
	<u>\$ 3,381,151</u>	<u>\$ 3,785,388</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 247,880	\$ 209,998
Accrued interest	23,259	23,630
Derivative instruments	28,944	36,413
Deferred income taxes	20,172	6,911
Current portion of long-term debt	—	287,092
Other current liabilities	20,582	19,683
Current liabilities of discontinued operations	—	45,647
Total current liabilities	340,837	629,374
Long-term debt	1,693,044	1,582,280
Asset retirement obligations	77,898	73,011
Other liabilities	76,259	73,463
Long-term liabilities of discontinued operations	—	74,473
Total liabilities	2,188,038	2,432,601
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 114,525,673 and 113,594,788 shares issued and outstanding	11,454	11,359
Capital surplus	2,486,994	2,684,269
Accumulated deficit	(1,287,063)	(1,424,905)
Accumulated other comprehensive (loss) income	(18,272)	82,064
Total shareholders' equity	1,193,113	1,352,787
	<u>\$ 3,381,151</u>	<u>\$ 3,785,388</u>

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2011	2010	2009
Revenues:			
Oil, natural gas, and NGL sales	\$ 703,531	\$ 707,692	\$ 655,579
Interest and other	1,026	989	800
Total revenues	<u>704,557</u>	<u>708,681</u>	<u>656,379</u>
Costs, expenses, and other:			
Lease operating expenses	99,158	92,394	119,472
Production and property taxes	40,632	43,656	40,147
Transportation and processing costs	13,728	13,242	12,855
General and administrative	65,105	64,886	65,254
Depreciation, depletion, and amortization	219,684	187,973	247,158
Ceiling test write-down of oil and gas properties	—	—	1,376,822
Interest expense	149,755	149,891	161,083
Realized and unrealized gains on derivative instruments, net	(88,064)	(150,132)	(132,148)
Other, net	17,164	7,339	26,126
Total costs, expenses, and other	<u>517,162</u>	<u>409,249</u>	<u>1,916,769</u>
Earnings (loss) from continuing operations before income taxes	187,395	299,432	(1,260,390)
Income tax	89,135	109,770	(466,601)
Net earnings (loss) from continuing operations	98,260	189,662	(793,789)
Net earnings (loss) from discontinued operations	44,569	37,859	(129,344)
Net earnings (loss)	142,829	227,521	(923,133)
Less: net earnings attributable to noncontrolling interest	4,987	—	—
Net earnings (loss) attributable to Forest Oil Corporation	<u>\$ 137,842</u>	<u>\$ 227,521</u>	<u>\$ (923,133)</u>
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	\$.86	\$ 1.68	\$ (7.61)
Earnings (loss) from discontinued operations35	.33	(1.24)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	<u>\$ 1.21</u>	<u>\$ 2.01</u>	<u>\$ (8.85)</u>
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:			
Earnings (loss) from continuing operations	\$.85	\$ 1.67	\$ (7.61)
Earnings (loss) from discontinued operations34	.33	(1.24)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	<u>\$ 1.19</u>	<u>\$ 2.00</u>	<u>\$ (8.85)</u>
Amounts attributable to Forest Oil Corporation common shareholders:			
Net earnings (loss) from continuing operations	\$ 98,260	\$ 189,662	\$ (793,789)
Net earnings (loss) from discontinued operations	39,582	37,859	(129,344)
Net earnings (loss)	<u>\$ 137,842</u>	<u>\$ 227,521</u>	<u>\$ (923,133)</u>

See accompanying Notes to Consolidated Financial Statements.

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

	<u>Common Stock</u>		<u>Capital Surplus</u>	<u>Retained Earnings (Accumulated Deficit)</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Forest Oil Corporation Shareholders' Equity</u>	<u>Noncontrolling Interest</u>	<u>Total Shareholders' Equity</u>
	<u>Shares</u>	<u>Amount</u>						
Balances at January 1, 2009.....	97,040	\$ 9,704	\$2,354,903	\$ (729,293)	\$ 37,598	\$ 1,672,912	\$ —	\$ 1,672,912
Common stock issued, net of offering costs	14,375	1,438	254,779	—	—	256,217	—	256,217
Exercise of stock options.....	171	17	3,049	—	—	3,066	—	3,066
Employee stock purchase plan	123	12	1,499	—	—	1,511	—	1,511
Restricted stock issued, net of cancellations	657	66	(66)	—	—	—	—	—
Amortization of stock-based compensation	—	—	26,820	—	—	26,820	—	26,820
Tax impact of employee stock option exercises	—	—	12,253	—	—	12,253	—	12,253
Other, net.....	(29)	(3)	(548)	—	—	(551)	—	(551)
Comprehensive loss:								
Net loss.....	—	—	—	(923,133)	—	(923,133)	—	(923,133)
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	2,152	2,152	—	2,152
Foreign currency translation.....	—	—	—	—	27,907	27,907	—	27,907
Total comprehensive loss						(893,074)	—	(893,074)
Balances at December 31, 2009	112,337	11,234	2,652,689	(1,652,426)	67,657	1,079,154	—	1,079,154
Exercise of stock options.....	458	46	8,653	—	—	8,699	—	8,699
Employee stock purchase plan	64	6	1,431	—	—	1,437	—	1,437
Restricted stock issued, net of cancellations	889	88	(88)	—	—	—	—	—
Amortization of stock-based compensation	—	—	28,440	—	—	28,440	—	28,440
Other, net.....	(153)	(15)	(6,856)	—	—	(6,871)	—	(6,871)
Comprehensive earnings:								
Net earnings	—	—	—	227,521	—	227,521	—	227,521
Increase in unfunded postretirement benefits, net of tax	—	—	—	—	(746)	(746)	—	(746)
Foreign currency translation.....	—	—	—	—	15,153	15,153	—	15,153
Total comprehensive earnings						241,928	—	241,928
Balances at December 31, 2010	113,595	11,359	2,684,269	(1,424,905)	82,064	1,352,787	—	1,352,787

See accompanying Notes to Consolidated Financial Statements.

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

	<u>Common Stock</u>		<u>Capital Surplus</u>	<u>Retained Earnings (Accumulated Deficit)</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Forest Oil Corporation Shareholders' Equity</u>	<u>Noncontrolling Interest</u>	<u>Total Shareholders' Equity</u>
	<u>Shares</u>	<u>Amount</u>						
Balances at December 31, 2010.....	113,595	11,359	2,684,269	(1,424,905)	82,064	1,352,787	—	1,352,787
Issuance of Lone Pine Resources Inc. common stock.....	—	—	112,610	—	(18,007)	94,603	83,572	178,175
Spin-off of Lone Pine Resources Inc.	—	—	(333,568)	—	(54,125)	(387,693)	(82,242)	(469,935)
Exercise of stock options	192	19	2,363	—	—	2,382	—	2,382
Employee stock purchase plan.....	96	10	1,331	—	—	1,341	—	1,341
Restricted stock issued, net of cancellations	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)
Comprehensive earnings:								
Net earnings.....	—	—	—	137,842	—	137,842	4,987	142,829
Increase in unfunded postretirement benefits, net of tax	—	—	—	—	(6,669)	(6,669)	—	(6,669)
Foreign currency translation	—	—	—	—	(21,535)	(21,535)	(6,317)	(27,852)
Total comprehensive earnings						109,638	(1,330)	108,308
Balances at December 31, 2011.....	<u>114,526</u>	<u>\$ 11,454</u>	<u>\$2,486,994</u>	<u>\$ (1,287,063)</u>	<u>\$ (18,272)</u>	<u>\$ 1,193,113</u>	<u>\$ —</u>	<u>\$ 1,193,113</u>

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2011	2010	2009
Operating activities:			
Net earnings (loss).....	\$ 142,829	\$ 227,521	\$ (923,133)
Less: net earnings (loss) from discontinued operations	44,569	37,859	(129,344)
Net earnings (loss) from continuing operations	98,260	189,662	(793,789)
Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations:			
Depreciation, depletion, and amortization	219,684	187,973	247,158
Deferred income tax	58,994	123,671	(537,416)
Unrealized (gains) losses on derivative instruments, net	(39,087)	(37,920)	176,018
Ceiling test write-down of oil and gas properties.....	—	—	1,376,822
Stock-based compensation expense	20,536	18,143	16,209
Accretion of asset retirement obligations.....	6,082	6,158	7,302
Other, net	8,114	2,463	7,671
Changes in operating assets and liabilities:			
Accounts receivable	23,236	2,640	26,622
Other current assets	14,314	24,136	33,241
Accounts payable and accrued liabilities	(6,470)	(62,435)	(36,820)
Accrued interest and other current liabilities	(5,566)	(7,766)	13,356
Net cash provided by operating activities of continuing operations	398,097	446,725	536,374
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development, acquisition, and leasehold costs	(873,877)	(556,988)	(545,357)
Other fixed assets costs	(6,968)	(5,143)	(31,274)
Proceeds from sales of assets	121,115	139,077	933,492
Other, net	—	—	28
Net cash (used) provided by investing activities of continuing operations	(759,730)	(423,054)	356,889
Financing activities:			
Proceeds from bank borrowings	160,000	—	747,000
Repayments of bank borrowings	(55,000)	—	(1,937,000)
Issuance of senior notes, net of issuance costs	—	—	559,767
Redemption of senior notes	(285,000)	(152,038)	(970)
Proceeds from common stock offering, net of offering costs.....	—	—	256,217
Proceeds from the exercise of options and from employee stock purchase plan	3,723	10,136	4,577
Payment of debt issue costs	(8,191)	—	(3,385)
Change in bank overdrafts.....	17,116	6,378	(38,943)
Other, net	(5,953)	(6,687)	11,538
Net cash used by financing activities of continuing operations	(173,305)	(142,211)	(401,199)
Cash flows of discontinued operations:			
Operating cash flows	101,292	86,204	60,622
Investing cash flows	(255,470)	(218,155)	28,483
Financing cash flows	478,324	1,692	(115,665)
Net cash provided (used) by discontinued operations	324,146	(130,259)	(26,560)
Effect of exchange rate changes on cash.....	(3,476)	(277)	(488)
Net (decrease) increase in cash and cash equivalents	(214,268)	(249,076)	465,016
Net (increase) decrease in cash and cash equivalents of discontinued operations	(289)	8,370	(8,946)
Net (decrease) increase in cash and cash equivalents of continuing operations	(214,557)	(240,706)	456,070
Cash and cash equivalents of continuing operations at beginning of year	217,569	458,275	2,205
Cash and cash equivalents of continuing operations at end of year	<u>\$ 3,012</u>	<u>\$ 217,569</u>	<u>\$ 458,275</u>
Cash paid by continuing operations during the year for:			
Interest (net of amounts capitalized)	\$ 139,311	\$ 140,856	\$ 133,947
Income taxes	2,861	53,748	4,302
Non-cash investing activities of continuing operations:			
Increase (decrease) in accrued capital expenditures.....	\$ 27,235	\$ 16,405	\$ (61,765)
Increase (decrease) in asset retirement costs	3,109	(1,081)	1,114

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2011, 2010, and 2009

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids (“NGLs”) primarily in the United States. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest holds assets in several exploration and producing areas in the United States and has exploratory and development interests in two other countries. In December 2010, Forest announced its intention to separate its Canadian operations through an initial public offering of up to 19.9% of the common stock of its subsidiary, Lone Pine Resources Inc. (“Lone Pine”), followed by a distribution, or spin-off, of the remaining shares of Lone Pine held by Forest to its shareholders. On June 1, 2011, Lone Pine completed an initial public offering of 15 million shares of common stock. On September 30, 2011, Forest completed the spin-off of the 70 million shares of Lone Pine held by Forest in the form of a pro rata common stock dividend to all Forest shareholders. 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 this 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. The results of operations of Lone Pine are reported as discontinued operations due to the spin-off, with prior periods being recast for comparative purposes. All intercompany balances and transactions have been eliminated. Certain amounts in prior years' financial statements have been reclassified to conform to the 2011 financial statement presentation.

Assumptions, Judgments, and Estimates

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

The more significant areas requiring the use of assumptions, judgments, and estimates relate to volumes of oil and gas 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, determining impairments of investments in unproved properties, valuing deferred tax assets and goodwill, 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

In January 2010, the Financial Accounting Standards Board (“FASB”) issued oil and natural gas reserves estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and natural gas reserves estimation and disclosure requirements with the requirements in the Securities and Exchange Commission’s (“SEC”) final rule, “Modernization of Oil and Gas Reporting”, which was also effective for annual reports for fiscal years ending on or after December 31, 2009. These rules included, among other things, changes to pricing used to estimate oil and natural gas reserves, broadened the types of technologies that a company may use to establish oil and natural gas reserves estimates, and broadened the definition of oil and natural gas producing activities. Accordingly, the Company adopted both the FASB’s authoritative accounting guidance and the SEC’s rule as of December 31, 2009.

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During the periods presented, the Company's primary oil and gas operations were conducted in the United States and Canada. Upon the spin-off of Lone Pine on September 30, 2011, the Company no longer has any operations in Canada. All costs incurred in the acquisition, exploration, and development of

properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. For the years ended December 31, 2011, 2010, and 2009, Forest's continuing operations capitalized \$46.4 million, \$42.6 million, and \$41.5 million of general and administrative costs (including stock-based compensation), respectively. Interest costs related to significant unproved properties that are under development are also capitalized to oil and gas properties. During 2011, 2010, and 2009, Forest's continuing operations capitalized \$10.3 million, \$11.2 million, and \$12.2 million, respectively, of interest costs attributed to unproved properties.

Investments in unproved properties, including capitalized interest costs, are not depleted pending 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 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 assess individually 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.

The Company performs a ceiling test each quarter on a country-by-country basis. 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 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 (as discussed below), 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 basis 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. The December 31, 2011 ceiling test did not result in a write-down. The March 31, 2009 ceiling test resulted in a non-cash write-down of oil and gas property costs of \$1.4 billion in the United States cost center.

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

Depletion of proved oil and 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 has historically updated its quarterly depletion calculations with its quarter-end reserves estimates. Based on this accounting policy, the December 31, 2011 reserves estimates were used for the Company's fourth quarter 2011 depletion calculation.

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

Asset Retirement Obligations

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

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

	Year Ended December 31,	
	2011	2010
	(In Thousands)	
Asset retirement obligations at beginning of period	\$ 73,132	\$ 78,487
Accretion expense	6,082	6,158
Liabilities incurred	2,321	1,988
Liabilities settled	(3,103)	(4,009)
Disposition of properties	(282)	(6,423)
Revisions of estimated liabilities.....	788	(3,069)
Asset retirement obligations at end of period.....	<u>78,938</u>	<u>73,132</u>
Less: current asset retirement obligations	<u>(1,040)</u>	<u>(121)</u>
Long-term asset retirement obligations.....	<u>\$ 77,898</u>	<u>\$ 73,011</u>

Oil, Natural Gas, and NGL Sales

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

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued. At December 31, 2011 and 2010, the Company had gas imbalance payables of \$7.8 million and \$7.7 million, respectively, and gas imbalance receivables of \$6.9 million and \$7.0 million, respectively.

In 2011, sales to one purchaser were approximately 22%, or \$151.9 million, of the Company's total revenues from continuing operations. In 2010, sales to two purchasers were approximately 20%, or \$145.1 million, and 10%, or \$73.2 million, respectively, of the Company's total revenues from continuing operations. In 2009, sales to two purchasers were approximately 17%, or \$108.6 million, and 10%, or \$66.9 million, respectively, of the Company's total revenues from continuing operations. Forest's revenues from continuing operations are attributable to the United States. Forest believes that the loss of one or more of the Company's current oil, natural gas, and NGL purchasers would not have a material adverse effect on the Company's ability to sell its production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

Accounts Receivable

The components of accounts receivable related to continuing operations are as follows:

	December 31,	
	2011	2010
	(In Thousands)	
Oil, natural gas, and NGL sales.....	\$ 58,799	\$ 61,538
Joint interest billings.....	14,451	15,877
Tax incentive refunds due from Texas.....	6,604	14,291
Other	698	12,440
Allowance for doubtful accounts.....	<u>(1,463)</u>	<u>(1,821)</u>
Total accounts receivable.....	<u>\$ 79,089</u>	<u>\$ 102,325</u>

Forest's accounts receivable are primarily from purchasers of the Company's oil, natural gas, and NGL sales and from other exploration and production companies which own working interests in the properties that the Company operates. This industry concentration could adversely impact Forest's overall credit risk because the Company's customers and working

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

Income Taxes

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

Earnings (Loss) per Share

Basic earnings (loss) per share is computed using the two-class method by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. The two-class method of computing earnings per share is required to be used since Forest has participating securities. The two-class method is an earnings allocation formula that determines earnings 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 issued under Forest's stock incentive plans do not participate in dividends. Performance units issued under Forest's stock incentive plans do not participate in dividends in their current form. Holders of performance units participate in dividends paid during the performance units' vesting period only after the performance units vest with common shares being earned by the holders of the performance units. Performance units may vest with no common shares being earned, 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.

Under the treasury stock method, diluted earnings (loss) per share is computed by dividing (a) net earnings (loss), adjusted for the effects of certain contracts that provide the issuer or holder with a choice between settlement methods, by (b) the weighted average number of common shares outstanding, adjusted for the dilutive effect, if any, of potential common shares (e.g. stock options, unvested restricted stock grants, unvested phantom stock units that may be settled in shares, and unvested performance units). No potential common shares are included in the computation of any diluted per share amount when a net loss exists. Unvested restricted stock grants were not included in the calculations of diluted earnings per share for the years ended December 31, 2011 and 2010 as their inclusion would have an antidilutive effect. Stock options, unvested restricted stock grants, and unvested phantom stock units that may be settled in shares were not included in the calculation of diluted loss per share for the year ended December 31, 2009 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,								
	2011			2010			2009		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In Thousands)								
Net earnings (loss)	\$ 98,260	\$ 44,569	\$ 142,829	\$ 189,662	\$ 37,859	\$ 227,521	\$ (793,789)	\$ (129,344)	\$ (923,133)
Net earnings attributable to noncontrolling interest.....	—	(4,987)	(4,987)	—	—	—	—	—	—
Net earnings attributable to participating securities	(2,037)	(821)	(2,858)	(3,736)	(746)	(4,482)	—	—	—
Net earnings (loss) attributable to common stock for basic earnings (loss) per share	96,223	38,761	134,984	185,926	37,113	223,039	(793,789)	(129,344)	(923,133)
Adjustment for liability classified stock-based compensation awards	—	(707)	(707)	—	500	500	—	—	—
Net earnings (loss) for diluted earnings (loss) per share	<u>\$ 96,223</u>	<u>\$ 38,054</u>	<u>\$ 134,277</u>	<u>\$ 185,926</u>	<u>\$ 37,613</u>	<u>\$ 223,539</u>	<u>\$ (793,789)</u>	<u>\$ (129,344)</u>	<u>\$ (923,133)</u>

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Weighted average common shares outstanding during the period for basic earnings (loss) per share	111,690	110,809	104,336
Dilutive effects of potential common shares	1,178	689	—
Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares, for diluted earnings (loss) per share	<u>112,868</u>	<u>111,498</u>	<u>104,336</u>

Stock-Based Compensation

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

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value, other than the derivative instruments that meet the normal purchases and sales exception. The Company has not elected to designate its derivative instruments as hedges and, therefore, records all changes in fair value of its derivative instruments through earnings, with such changes reported in a single line item on the statements of operations together with 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, 2011 and 2010 totaled \$25.0 million and \$23.9 million, respectively, and are being amortized over the life of the respective debt instruments.

Inventory

Inventories, which are carried at average cost with adjustments made from time to time to recognize, as appropriate, any reductions in value, were comprised of \$10.1 million and \$22.6 million of materials and supplies as of December 31, 2011 and 2010, 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 make an annual impairment assessment 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 events or circumstances change between annual tests indicating a possible impairment. The impairment assessment requires the Company to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. Although the Company bases its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. Downward revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or depressed oil and natural gas prices could lead to an impairment of goodwill in future periods. The Company had no goodwill impairments for the years ended December 31, 2011, 2010, and 2009.

Comprehensive Earnings (Loss)

Comprehensive earnings (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 changes in the unfunded postretirement benefits.

The components of accumulated other comprehensive income (loss) for the years ended December 31, 2011, 2010, and 2009 are as follows:

	Foreign Currency Translation	Unfunded Postretirement Benefits ⁽¹⁾	Accumulated Other Comprehensive Income (Loss)
	(In Thousands)		
Balance at January 1, 2009	\$ 50,607	\$ (13,009)	\$ 37,598
2009 activity.....	27,907	2,152	30,059
Balance at December 31, 2009	78,514	(10,857)	67,657
2010 activity.....	15,153	(746)	14,407
Balance at December 31, 2010	93,667	(11,603)	82,064
2011 activity.....	(93,667)	(6,669)	(100,336)
Balance at December 31, 2011	<u>\$ —</u>	<u>\$ (18,272)</u>	<u>\$ (18,272)</u>

(1) Net of income tax expense (benefit) of \$(3.7) million, \$(.5) million, and \$1.2 million for 2011, 2010, and 2009, respectively.

Impact of Recently Issued Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income, Presentation of Comprehensive Income* ("ASU 2011-05"), which provides amendments that will result in more converged guidance on how comprehensive income is presented under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards ("IFRS"). ASU 2011-05 requires an entity to present items of net income, items of other comprehensive income, and total comprehensive income either in a single continuous statement or in two separate consecutive statements and eliminates the option to report other comprehensive income and its components in the statement of shareholders' equity. ASU 2011-05 also requires entities to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income. In December 2011, the FASB issued Accounting Standards Update No. 2011-12, *Comprehensive Income, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* ("ASU 2011-12"), which indefinitely defers the requirements in ASU 2011-05 to present on the face of the financial statements the effects of reclassifications out of accumulated other

comprehensive income on the components of net income and other comprehensive income. Both ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011, and should be applied retrospectively. The adoption of this authoritative guidance will not have an impact on Forest's financial position or results of operations, but will require Forest to present the statements of comprehensive income separately from the statements of shareholders' equity, as these statements are currently presented on a combined basis.

In June 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"), which amends the current U.S. GAAP fair value measurement and disclosure guidance, to converge U.S. GAAP and IFRS requirements for measuring amounts at fair value as well as disclosures about these measurements. Many of the amendments clarify existing concepts and are not expected to result in significant changes to how companies apply the fair value principles. This authoritative guidance is effective for interim and annual periods beginning after December 15, 2011. Forest is currently evaluating the impact that the adoption of this authoritative guidance will have on its fair value measurements and disclosures.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, *Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment* ("ASU 2011-08"), which permits entities to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount to determine whether it is necessary to perform the two-step goodwill impairment test. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, it is required to perform the first step of the two-step impairment test, which may then lead an entity to performing the second step as well. Entities have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to the first step of the two-step impairment test. This authoritative guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this authoritative accounting guidance may change the methodology Forest uses to test its goodwill for impairment depending on the events or circumstances at the time the test is performed.

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

(2) PROPERTY AND EQUIPMENT:

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

	December 31,	
	2011	2010
	(In Thousands)	
Oil and gas properties:		
Proved	\$ 8,825,142	\$ 8,058,876
Unproved.....	675,995	646,264
Accumulated depletion	(6,901,997)	(6,688,012)
Net oil and gas properties	2,599,140	2,017,128
Other property and equipment:		
Gas gathering, furniture and fixtures, computer hardware and software, and other equipment.....	99,965	95,577
Accumulated depreciation and amortization	(47,989)	(42,432)
Net other property and equipment.....	51,976	53,145
Total net property and equipment ⁽¹⁾	\$ 2,651,116	\$ 2,070,273

(1) At December 31, 2011 and 2010, \$98.7 million and \$91.6 million, respectively, of the Company's total net property and equipment of continuing operations was located in foreign countries. The remaining total net property and equipment was located in the United States.

The following table sets forth a summary of Forest's investment in unproved properties as of December 31, 2011, by the year in which such costs were incurred:

	<u>Total</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008 and Prior</u>
	(In Thousands)				
United States:					
Acquisition costs	\$ 539,439	\$ 171,137	\$ 27,394	\$ 29,894	\$ 311,014
Exploration costs	71,661	59,886	3,861	1,786	6,128
Total United States	<u>611,100</u>	<u>231,023</u>	<u>31,255</u>	<u>31,680</u>	<u>317,142</u>
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	64,155	5,767	1,968	1,451	54,969
Total International	<u>64,895</u>	<u>5,767</u>	<u>1,968</u>	<u>1,451</u>	<u>55,709</u>
Total	<u>\$ 675,995</u>	<u>\$ 236,790</u>	<u>\$ 33,223</u>	<u>\$ 33,131</u>	<u>\$ 372,851</u>

The majority of the U.S. unproved oil and gas property costs, or those not being depleted, relate to oil and gas property acquisitions and leasehold acquisition costs as well as work-in-progress on various projects. The Company expects that substantially all of its unproved property costs in the U.S. as of December 31, 2011 will be reclassified to proved properties within ten years. Forest's exploration project in South Africa accounts for all of the international costs not being amortized as of December 31, 2011. The Company continues to pursue commercial development of the Ibhubesi field discovery in South Africa including continued efforts toward securing gas sales contracts.

Divestitures

During the years ended December 31, 2011 and 2010, Forest sold various U.S. oil and natural gas properties for total proceeds of \$121.0 million and \$75.9 million, respectively. During 2010, Forest also entered into sale-leaseback transactions involving drilling rigs, receiving \$63.1 million in total proceeds. During 2009, Forest sold all of its oil and natural gas properties located in the Permian Basin in West Texas and New Mexico for approximately \$908.3 million in cash and also sold other U.S. oil and natural gas properties for total proceeds of \$25.0 million.

Acquisitions - Subsequent Event

In February 2012, the Company paid \$66.0 million in cash and issued 2.7 million shares of common stock, valued at approximately \$36 million, pursuant to a lease purchase agreement whereby Forest acquired leases on unproved oil and natural gas properties in the Wolfbone oil play in the Permian Basin in Texas.

(3) DEBT:

The components of debt are as follows:

	December 31, 2011			December 31, 2010			
	Principal	Unamortized Premium (Discount)	Total	Principal	Unamortized Premium (Discount)	Other ⁽¹⁾	Total
	(In Thousands)						
Credit Facility.....	\$ 105,000	\$ —	\$ 105,000	\$ —	\$ —	\$ —	\$ —
8% Senior Notes due 2011 ⁽²⁾	—	—	—	285,000	1,292	800	287,092
7% Senior Subordinated Notes due 2013.....	12	—	12	12	—	—	12
8½% Senior Notes due 2014.....	600,000	(12,389)	587,611	600,000	(18,210)	—	581,790
7¼% Senior Notes due 2019.....	1,000,000	421	1,000,421	1,000,000	478	—	1,000,478
Total debt.....	1,705,012	(11,968)	1,693,044	1,885,012	(16,440)	800	1,869,372
Less: current portion of long-term debt.....	—	—	—	(285,000)	(1,292)	(800)	(287,092)
Long-term debt.....	<u>\$ 1,705,012</u>	<u>\$ (11,968)</u>	<u>\$ 1,693,044</u>	<u>\$ 1,600,012</u>	<u>\$ (17,732)</u>	<u>\$ —</u>	<u>\$ 1,582,280</u>

(1) Represents the unamortized portion of deferred gains realized upon the termination of interest rate swaps in 2002 that were accounted for as fair value hedges. The gains were amortized as a reduction of interest expense over the terms of the notes.

(2) Redeemed in December 2011.

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., consisting of a \$1.5 billion credit facility maturing in June 2016. Subject to the agreement of Forest and the applicable lenders, the size of the Credit Facility may be increased by \$300.0 million, to a total of \$1.8 billion.

Forest's availability under the Credit Facility is governed by a borrowing base. As of December 31, 2011, the borrowing base under the Credit Facility was \$1.25 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of Forest's oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. 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. The borrowing base was reaffirmed at \$1.25 billion in October 2011 and the next scheduled redetermination of the borrowing base will occur on or about May 1, 2012.

The borrowing base is also subject to change in the event (i) Forest or its Restricted Subsidiaries 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 then-existing senior notes, or (ii) Forest sells oil and natural gas properties included in the borrowing base having a fair market value in excess of 10% of the borrowing base then in effect. A lowering of the borrowing base could require Forest to repay indebtedness in excess of the borrowing base in order to cover the deficiency.

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

- (i) the greatest of (a) the prime rate announced by JPMorgan Chase Bank, N.A., (b) the federal funds effective rate from time to time plus ½ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by Forest) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or
- (ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 basis points, depending on borrowing base utilization.

The Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also includes a financial covenant. The Credit Facility provides that Forest will not permit its ratio of total

debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.50 to 1.00 at any time.

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

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

Of the \$1.5 billion total nominal amount under the Credit Facility, JPMorgan and eleven other banks hold approximately 68% of the total commitments, with each of these twelve lenders holding an equal share. 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, 2011, there were outstanding borrowings of \$105.0 million under the Credit Facility at a weighted average interest rate of 2.1% and Forest had used the Credit Facility for \$2.1 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of \$1.1 billion.

Prior to entering into the Credit Facility, the previous combined credit facility, the Second Amended and Restated Credit Agreement dated as of June 6, 2007, consisting of U.S. and Canadian facilities (the "Combined Credit Facility") was amended on May 25, 2011, to, among other things, remove any collateral owned by Lone Pine or any of its subsidiaries from the collateral securing the U.S. portion of the Combined Credit Facility, terminate the previous Canadian portion of the Combined Credit Facility, terminate various guaranties securing the Canadian portion of the Combined Credit Facility, release collateral securing the Canadian portion of the Combined Credit Facility, and terminate certain liens and mortgages securing the Canadian portion of the Combined Credit Facility.

8½% Senior Notes Due 2014

On February 17, 2009, Forest issued \$600.0 million in principal amount of 8½% senior notes due 2014 (the "8½% Notes") at 95.15% of par for net proceeds of \$559.8 million, after deducting initial purchaser discounts. The 8½% Notes are redeemable, at the Company's option, in whole or in part, at any time at the principal amount, plus accrued interest, and a make-whole premium. Due to the amortization of the discount, the effective interest rate on the 8½% Notes is 9.47%.

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%.

Forest may redeem the 7¼% Notes at any time beginning on or after June 15, 2012 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest:

2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

Forest may also redeem the 7¼% Notes, in whole or in part, at a price equal to the principal amount plus a make-whole premium, at any time prior to June 15, 2012, using a discount rate of the Treasury rate plus 0.50%, plus accrued but unpaid interest.

8% Senior Notes Due 2011

In December 2001, Forest issued \$160.0 million in principal amount of 8% senior notes due 2011 (the "8% Notes") at par for proceeds of \$157.5 million (net of related offering costs). In July 2004, Forest issued an additional \$125.0 million in principal amount of 8% Notes at 107.75% of par for proceeds of \$133.3 million (net of related offering costs). In December 2011, Forest redeemed the 8% Notes.

7¾% Senior Notes Due 2014

In December 2009, Forest notified the trustee and note holders of the \$150.0 million of 7¾% senior notes due 2014 (the "7¾% Notes") that it was calling the 7¾% Notes. This notice was irrevocable after it was given.

The 7¾% Notes were redeemed in January 2010 at 101.292% of par and a net gain of \$4.6 million was recognized in January 2010 upon redemption. The net gain was recognized due to the write-off of unamortized deferred gains that resulted from the previous termination of interest rate swaps related to the 7¾% Notes.

Principal Maturities

Principal maturities of the Company's debt at December 31, 2011 are as follows:

	Principal Maturities
	(In Thousands)
2012.....	\$ —
2013.....	12
2014.....	600,000
2015.....	—
2016.....	105,000
Thereafter.....	1,000,000

(4) INCOME TAXES:

Income Tax Provision

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Current:			
Federal.....	\$ (201)	\$ (16,393)	\$ 62,366
Foreign.....	28,921	—	—
State.....	1,421	2,492	8,449
	<u>30,141</u>	<u>(13,901)</u>	<u>70,815</u>
Deferred:			
Federal.....	56,482	121,111	(525,739)
State.....	2,512	2,560	(11,677)
	<u>58,994</u>	<u>123,671</u>	<u>(537,416)</u>
	<u>\$ 89,135</u>	<u>\$ 109,770</u>	<u>\$ (466,601)</u>

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

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
United States Federal	\$ 188,421	\$ 301,349	\$ (1,259,729)
Foreign	(1,026)	(1,917)	(661)
	<u>\$ 187,395</u>	<u>\$ 299,432</u>	<u>\$ (1,260,390)</u>

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 income from continuing operations is as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	\$ 65,947	\$ 105,472	\$ (440,905)
State income taxes, net of federal income tax benefits	2,214	3,526	(14,080)
Change in the valuation allowance for deferred tax assets	—	—	(8,913)
Canadian dividend tax, net of U.S. tax benefit.....	18,460	—	—
Effect of federal, state, and foreign tax on permanent differences.....	4,025	4,030	1,725
Other.....	(1,511)	(3,258)	(4,428)
Total income tax.....	<u>\$ 89,135</u>	<u>\$ 109,770</u>	<u>\$ (466,601)</u>

Net Deferred Tax Assets and Liabilities

The components of the net deferred tax assets and liabilities of Forest's continuing operations at December 31, 2011 and 2010 are as follows:

	December 31,	
	2011	2010
	(In Thousands)	
Deferred tax assets:		
Property and equipment.....	\$ 93,032	\$ 139,992
Investment in PERL common stock and Note.....	—	18,011
Accrual for postretirement benefits	11,545	7,831
Stock-based compensation accruals	7,921	15,471
Net operating loss carryforwards.....	60,965	42,992
Alternative minimum tax credit carryforward.....	54,776	54,584
Other	8,418	9,803
Total gross deferred tax assets.....	<u>236,657</u>	<u>288,684</u>
Less valuation allowance.....	—	—
Net deferred tax assets	<u>236,657</u>	<u>288,684</u>
Deferred tax liabilities:		
Unrealized gains on derivative contracts, net.....	(25,713)	(11,574)
Total gross deferred tax liabilities.....	<u>(25,713)</u>	<u>(11,574)</u>
Net deferred tax assets	<u>\$ 210,944</u>	<u>\$ 277,110</u>

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

	December 31,	
	2011	2010
	(In Thousands)	
Current deferred tax liabilities	\$ (20,172)	\$ (6,911)
Non-current deferred tax assets	231,116	284,021
Net deferred tax assets	<u>\$ 210,944</u>	<u>\$ 277,110</u>

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2011 were approximately \$169.7 million, with \$8.2 million scheduled to expire in 2019, \$1.4 million scheduled to expire in 2020, and the remaining scheduled to expire after 2030.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2007. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2007. 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, 1999.

Alternative Minimum Tax Credits

The Alternative Minimum Tax credit carryforward available to reduce future U.S. federal regular taxes equaled an aggregate amount of \$54.8 million at December 31, 2011, 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,		
	2011	2010	2009
	(In Thousands)		
Gross unrecognized tax benefits at beginning of period.....	\$ 3,345	\$ 2,665	\$ 3,167
Increases as a result of tax positions taken during a prior period	—	1,078	1,138
Decreases as a result of tax positions taken during a prior period.....	(516)	(398)	(1,640)
Gross unrecognized tax benefits at end of period	<u>\$ 2,829</u>	<u>\$ 3,345</u>	<u>\$ 2,665</u>

(5) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2011, the Company had 200.0 million shares of common stock, par value \$.10 per share, authorized and 114.5 million shares issued and outstanding.

In May 2009, the Company issued 14.4 million shares of common stock at a price of \$18.25 per share. Net proceeds from this offering were \$256.2 million after deducting underwriting discounts and commissions and offering expenses.

In February 2012, the Company issued 2.7 million shares of common stock, valued at approximately \$36 million, as partial consideration pursuant to a lease purchase agreement whereby Forest acquired leases on unproved oil and natural gas properties in the Wolfbone oil play in the Permian Basin in Texas.

Preferred Stock

Forest has 10.0 million shares of preferred stock, par value \$.01 per share, authorized under its Articles of Incorporation. Of those, 7.4 million shares are designated as Senior Preferred Stock and 2.7 million shares are designated as Junior Preferred stock. No preferred stock is issued or outstanding.

Lone Pine

In December 2010, Forest announced its intention to separate its Canadian operations through an initial public offering of up to 19.9% of the common stock of its wholly-owned subsidiary, Lone Pine, which would hold Forest's ownership interests in its Canadian operations, followed by a distribution, or spin-off, of Forest's remaining shares of Lone Pine to Forest's shareholders. 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 "Income tax" on the Consolidated Statement of Operations. On June 1, 2011, Lone Pine completed an initial public offering of 15 million shares of its common stock at a price of \$13.00 per share (\$12.22 per share net of underwriting discounts and commissions). Upon completion of the offering, Forest retained controlling interest in Lone Pine, owning approximately 82% of the outstanding shares of Lone Pine's common stock. The net proceeds from the offering received by Lone Pine, after deducting underwriting discounts and commissions and offering expenses, were approximately \$178.0 million. Lone Pine used the net proceeds to pay \$29.2 million to Forest as partial consideration for Forest's contribution to Lone Pine of Forest's direct and indirect interests in its Canadian operations. Additionally, Lone Pine used the remaining net proceeds and borrowings under Lone Pine's credit facility to repay Lone Pine's outstanding indebtedness owed to Forest, consisting of a note payable, intercompany advances, and accrued interest, of \$400.5 million. Forest completed the spin-off of its remaining shares of Lone Pine on September 30, 2011, in the form of a pro rata common stock dividend to all Forest shareholders of record as of the close of business on September 16, 2011 (the "Record Date"). Forest shareholders received .61248511 of a share of Lone Pine common stock for every share of Forest common stock held as of the close of business on the Record Date. 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	\$ 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 and transfers from (to) noncontrolling interest.....	<u>\$ (102,583)</u>

Rights Agreement

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

(6) STOCK-BASED COMPENSATION:

Stock-based Compensation Plans

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the "2001 Plan") and in 2007, the Company adopted the Forest Oil Corporation 2007 Stock Incentive Plan (the "2007 Plan" and together with the 2001 Plan the "Stock-based Compensation Plans") under which qualified and non-qualified stock options, restricted stock, performance units, phantom stock units, and other awards may be granted to employees, consultants, and non-employee directors. The aggregate number of shares of common stock that the Company may issue under the 2007 Plan may not exceed 8.7 million shares. As of December 31, 2011, the Company had 4.1 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, 2011.

Compensation Costs

The table below sets forth stock-based compensation of continuing operations recorded during the years ended December 31, 2011, 2010, and 2009, and the remaining unamortized amounts and weighted average amortization period as of December 31, 2011.

	<u>Stock Options⁽¹⁾</u>	<u>Restricted Stock⁽²⁾</u>	<u>Performance Units</u>	<u>Phantom Stock Units</u>	<u>Total⁽³⁾⁽⁴⁾</u>
	(In Thousands)				
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.....	<u>\$ 873</u>	<u>\$ 17,121</u>	<u>\$ 2,221</u>	<u>\$ 22</u>	<u>\$ 20,237</u>
Unamortized stock-based compensation costs as of December 31, 2011	\$ —	\$ 21,121	\$ 7,260	\$ 11,293	⁽⁵⁾ \$ 39,674
Weighted average amortization period remaining as of December 31, 2011.....	—	2.0	1.7	1.8	1.9
Year ended December 31, 2010:					
Total stock-based compensation costs.....	\$ 563	\$ 25,377	\$ 1,907	\$ 3,129	\$ 30,976
Less: stock-based compensation costs capitalized	(241)	(9,492)	(469)	(1,010)	(11,212)
Stock-based compensation costs expensed.....	<u>\$ 322</u>	<u>\$ 15,885</u>	<u>\$ 1,438</u>	<u>\$ 2,119</u>	<u>\$ 19,764</u>
Year ended December 31, 2009:					
Total stock-based compensation costs.....	\$ 774	\$ 25,448	\$ —	\$ 1,000	\$ 27,222
Less: stock-based compensation costs capitalized	(311)	(10,301)	—	(322)	(10,934)
Stock-based compensation costs expensed.....	<u>\$ 463</u>	<u>\$ 15,147</u>	<u>\$ —</u>	<u>\$ 678</u>	<u>\$ 16,288</u>

- (1) In conjunction with the spin-off of Lone Pine, both the number of options outstanding and the option exercise prices were adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans, which were designed to equalize an award's value before and after an equity restructuring. Because the actual option modifications were calculated based on Forest's average stock price over a period of time before and after the spin-off of Lone Pine rather than the stock price immediately before and after the spin-off, \$1.1 million in incremental compensation cost resulted, \$.4 million of which was capitalized. This cost was recognized in its entirety on September 30, 2011 because all options outstanding were vested as of that date.
- (2) In conjunction with the spin-off, the forfeiture restrictions on a portion of each outstanding restricted stock award lapsed because the holders of the restricted stock awards received unrestricted Lone Pine common shares in the spin-off. This resulted in an acceleration of the recognition of \$10.9 million of compensation costs associated with the restricted stock awards, \$4.9 million of which was capitalized.
- (3) The Company also maintains an employee stock purchase plan (which is not included in the table) under which \$.5 million, \$.5 million, and \$.6 million of compensation costs were recognized for the years ended December 31, 2011, 2010, and 2009, respectively.
- (4) In addition to the compensation costs set forth in the table above, in June 2011 the Company granted a cash-based long-term incentive award under which \$.1 million in compensation costs were recognized for the year ended December 31, 2011, and under which \$.5 million remains as unamortized stock-based compensation costs at December 31, 2011. The award is comprised of time-based and performance-based components. Under the time-based component, a cash payment will be made after three years dependent on the change in value of Forest's common stock during the three-year period, and under the performance-based component, a cash payment will be made after three years dependent on the total shareholder return on Forest's common stock in comparison to that of a peer group during the three-year period. The cash-based long-term incentive award has been accounted for as a liability within the Consolidated Financial Statements.
- (5) Based on the closing price of the Company's common stock on December 31, 2011.

Stock Options

The following table summarizes stock option activity in the Stock-based Compensation Plans for the years ended December 31, 2011, 2010, and 2009.

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands) ⁽²⁾	Number of Options Exercisable
Outstanding at January 1, 2009.....	2,097,267	\$ 21.13	\$ 376	1,898,316
Granted.....	—	—		
Exercised.....	(170,702)	17.96	671	
Cancelled.....	(108,146)	23.82		
Outstanding at December 31, 2009.....	1,818,419	21.26	7,387	1,722,216
Granted.....	—	—		
Exercised.....	(457,974)	18.99	6,027	
Cancelled.....	(32,750)	36.28		
Outstanding at December 31, 2010.....	1,327,695	21.67	22,531	1,283,232
Granted.....	—	—		
Exercised.....	(29,711)	18.55	331	
Cancelled.....	(13,273)	25.11		
Spin-off adjustment ⁽¹⁾	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

(1) In conjunction with the spin-off of Lone Pine, both the number of options outstanding and the option exercise prices were adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans. In conjunction with the spin-off, Lone Pine employees were deemed to have been involuntarily terminated under the terms of their option agreements and, therefore, had three months from September 30, 2011 to exercise their vested options before they were canceled.

(2) 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.

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, 2011:

Range of Exercise Prices	Stock Options Outstanding and Exercisable			
	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)
\$9.70 - 10.30.....	501,658	1.29	\$ 9.99	\$ 1,715
10.31 - 12.21.....	445,154	2.03	11.13	1,013
12.22 - 13.40.....	11,573	2.94	13.10	3
13.41 - 18.45.....	472,306	2.87	14.12	—
18.46 - 27.90.....	335,896	5.14	26.54	—
\$9.70 - 27.90.....	1,766,587	2.64	\$ 14.55	\$ 2,731

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, 2011, 2010, and 2009.

	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 ⁽³⁾	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)
Unvested at January 1, 2009.....	1,490,795	\$ 52.31		—	\$ —		163,954	\$ 51.10	
Awarded.....	839,618	18.21		—	—		360,578	18.22	
Vested.....	(119,145)	45.50	\$ 2,302	—	—	\$ —	(12,109)	33.28	\$ 236
Forfeited	(182,585)	42.91		—	—		(37,360)	34.41	
Unvested at December 31, 2009.....	2,028,683	39.44		—	—		475,063	27.91	
Awarded.....	1,006,163	24.69		264,500	31.63		153,135	25.96	
Vested.....	(645,660)	40.66	19,806	—	—	—	(65,140)	41.88	1,910
Forfeited	(116,865)	36.55		—	—		(52,449)	35.28	
Unvested at December 31, 2010.....	2,272,321	32.71		264,500	31.63		510,609	24.79	
Awarded.....	1,025,782	27.30		226,000	27.53		500	28.24	
Vested.....	(610,681)	61.33	18,416	—	—	—	(52,587)	60.04	1,449
Forfeited	(131,330)	23.51		(41,000)	29.98		(25,737)	19.12	
Spin-off adjustment ⁽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	

- (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 for by the Stock-based Compensation Plans. In addition, the initial stock prices used to measure Forest's total shareholder returns over the performance periods of the performance units were adjusted in accordance with the antidilution provisions provided for by the Stock-based Compensation Plans. The number of restricted stock awards outstanding was not adjusted as a result of the spin-off since holders of restricted stock awards received Lone Pine common shares in the spin-off.
- (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 agreements, and, therefore, all phantom stock units held by Lone Pine employees vested on September 30, 2011 and were settled in cash by Lone Pine. The single Lone Pine employee who held a performance unit award was deemed to have been involuntarily terminated under the terms of his performance unit agreement at the time of the spin-off and, therefore, his performance units vested on September 30, 2011, but with no shares deliverable under his agreement. No Forest restricted stock awards were held by Lone Pine employees at the time of the spin-off.
- (3) Of the unvested units of phantom stock at December 31, 2011, 6,080 units can be settled in cash, shares of common stock, or a combination of both at the discretion of the Company, while the remaining 1,232,737 units can only be settled in cash. The phantom stock units have been accounted for as a liability within the Consolidated Financial Statements. Of the 398,857 phantom stock units that vested during 2011, 5,500 units were settled in shares of common stock and 393,357 units were settled in cash. Of the 65,140 phantom stock units that vested during 2010, 63,750 units were settled in shares of common stock and 1,390 units were settled in cash. Of the 12,109 phantom stock units that vested in 2009, 7,429 were settled in shares of common stock and 4,680 units were settled in cash.

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

The grant date fair value of the phantom stock units was determined by averaging the high and low stock price of a share of common stock as published by the New York Stock Exchange on the date of grant. Phantom stock units outstanding prior to the fourth quarter of 2011 generally vest on the third anniversary of the date of the award. In the fourth quarter of 2011, the Company granted 941,300 phantom stock units that vest in one-third increments on each of the first three anniversaries of the date of grant. Like restricted stock, phantom stock units may vest earlier due to certain circumstances, as discussed above.

Forest granted performance units to its officers on May 21, 2010 and June 10, 2011. Under the terms of the award agreements, each performance unit represents a contractual right to receive one share of Forest's common stock; provided that the actual number of shares that may be deliverable under an award will range from 0% to 200% of the number of performance units awarded, depending on Forest's relative total shareholder return in comparison to an identified peer group over a thirty-six month performance period, the first of which ends on March 31, 2013 and the second of which ends on March 31, 2014. The grant date fair values of these awards were determined using a process that takes into account probability-weighted shareholder returns assuming a large number of possible stock price paths (which are modeled based on inputs such as volatility and the risk-free interest rate).

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to .8 million shares of common stock. Employees who are regularly scheduled to work more than 20 hours per week and more than five months in any calendar year may participate in the ESPP. Currently, under the terms of the ESPP, employees may elect each calendar quarter to have up to 15% of their annual base earnings withheld to purchase shares of common stock, up to a limit of \$25,000 of common stock per calendar year. The purchase price of a share of common stock purchased under the ESPP is equal to 85% of the lower of the beginning-of-quarter or end-of-quarter market price. ESPP participants are restricted from selling the shares of common stock purchased under the ESPP for a period of six months after purchase. As of December 31, 2011, the Company had .3 million shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2011, 2010, and 2009 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,		
	2011	2010	2009
Expected option life	3 months	3 months	3 months
Risk free interest rates.....	.02% - .15%	.08% - .17%	.08% - .22%
Estimated volatility	59%	38%	62%
Dividend yield.....	0%	0%	0%
Weighted average fair market value of purchase rights granted	\$5.00	\$7.78	\$4.70

(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 "Supplemental Executive Retirement Plan") 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 Supplemental Executive Retirement Plan 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. In conjunction with The Houston Exploration Company acquisition in June 2007, Forest assumed a non-qualified unfunded supplementary retirement plan (the "Houston Exploration SERP," and together with the "Supplemental Executive Retirement Plan," the "SERP"). The Houston Exploration SERP was curtailed and all benefit accruals were suspended effective January 1, 2008. 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, 2011, 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 2012 through 2016 and in the aggregate for the years 2017 through 2021 in the following amounts:

	2012	2013	2014	2015	2016	2017- 2021
	(In Thousands)					
Forest Pension Plan ⁽¹⁾	\$ 2,390	\$ 2,399	\$ 2,318	\$ 2,267	\$ 2,196	\$ 10,123
SERP.....	134	130	127	123	119	521
Wiser Pension Plan ⁽¹⁾	858	852	840	829	820	3,913
Postretirement Benefits Plan.....	716	710	704	684	659	3,498

(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 2012 totaling \$.1 million to the Plans and \$.6 million for the Postretirement Benefits Plan, net of retiree contributions and expected Medicare reimbursements, as applicable.

Benefit Obligations

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

	Year Ended December 31,			
	Pension Plans		Postretirement Benefits Plan	
	2011	2010	2011	2010
	(In Thousands)			
Benefit obligation at the beginning of the year	\$ 42,213	\$ 41,205	\$ 9,212	\$ 7,959
Service cost	—	—	825	668
Interest cost	1,836	2,005	529	430
Actuarial loss.....	3,931	2,273	3,645	740
Benefits paid.....	(3,225)	(3,270)	(779)	(717)
Medicare reimbursements	—	—	—	66
Retiree contributions	—	—	66	66
Benefit obligation at the end of the year	<u>\$ 44,755</u>	<u>\$ 42,213</u>	<u>\$ 13,498</u>	<u>\$ 9,212</u>

Fair Value of Plan Assets

The Company's Pension Plans' assets measured at fair value on a recurring basis are set forth by level within the fair value hierarchy in the table below as of the dates indicated (see Note 8 for information on the fair value hierarchy). There were no changes to the valuation techniques used during the period. There are no assets set aside under the SERP and the Postretirement Benefits Plan. During 2011, the amount of contributions in the case of the Postretirement Benefit Plan, equals the amount of benefits paid.

	December 31, 2011				December 31, 2010			
	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total
	(In Thousands)							
Investment funds—equities:								
Research equity portfolio ⁽¹⁾ ..	\$ —	\$ 9,681	\$ —	\$ 9,681	\$ —	\$ 10,000	\$ —	\$ 10,000
International stock funds ⁽²⁾ ...	10,363	—	—	10,363	11,001	—	—	11,001
Investment funds—fixed income:								
Short-term fund ⁽³⁾	1,549	—	—	1,549	267	—	—	267
Bond fund ⁽⁴⁾	4,166	—	—	4,166	8,180	—	—	8,180
Oil and gas royalty interests ⁽⁵⁾ ..	—	—	198	198	—	—	161	161
	<u>\$ 16,078</u>	<u>\$ 9,681</u>	<u>\$ 198</u>	<u>\$ 25,957</u>	<u>\$ 19,448</u>	<u>\$ 10,000</u>	<u>\$ 161</u>	<u>\$ 29,609</u>

- (1) This investment fund's assets are primarily large capitalization U.S. equities. The investment approach of this fund, which typically holds 110 - 130 securities, focuses on diversifying the investment portfolio by delegating the equity selection process to research analysts with expertise in their respective industries. Industry weights are kept similar to those of the S&P 500 Index. As of December 31, 2011, the sector weighting of this fund was comprised of the following: information technology (22%), financials (15%), energy (15%), health care (13%), consumer staples (11%), and other (24%). The fair value of this investment fund was determined based on the net asset value per unit provided by the investee. Forest performs procedures to validate the net asset value per unit provided by the investee. Such procedures include verifying a sample of the net asset values of the underlying securities, which are directly observable in the marketplace.
- (2) These two 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, 2011, the sector weighting of this fund, which seeks diversification across regions, countries, and market sectors, was comprised of the following: financials (20%), health care (17%), consumer discretionary (14%), information technology (13%), telecommunications services (11%), and other (25%). 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, 2011, 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 (29%), consumer discretionary (17%), consumer staples (16%), information technology (14%), and other (24%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are directly observable in the marketplace.
- (3) This investment fund's assets are high-quality money market instruments and short-term fixed income securities. This fund is actively managed as an enhanced cash strategy, seeking to derive excess returns versus money market fund indices by capturing term, transactional liquidity, credit, and volatility premiums. As of December 31, 2011, the sector weighting of this fund was comprised of the following: investment grade corporate bonds (44%), mortgage (15%), net cash equivalents (11%), and other (30%). 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.
- (4) This investment fund consists of a diversified portfolio of bonds. The 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, 2011, the sector weighting of this fund was comprised of the following: mortgage (48%), government-related (31%), non-U.S. dollar developed market (18%), and other (3%). 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) 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	
	2011	2010	2011	2010
	(In Thousands)			
Fair value of plan assets at beginning of the year.....	\$ 29,609	\$ 29,379	\$ —	\$ —
Actual return on plan assets	(1,566)	2,927	—	—
Retiree contributions.....	—	—	66	66
Medicare reimbursements.....	—	—	—	66
Employer contribution	1,139	573	713	585
Benefits paid.....	(3,225)	(3,270)	(779)	(717)
Fair value of plan assets at the end of the year	<u>\$ 25,957</u>	<u>\$ 29,609</u>	<u>\$ —</u>	<u>\$ —</u>

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,	
	2011	2010
	Oil and Gas Royalty Interests	
	(In Thousands)	
Balance at beginning of period.....	\$ 161	\$ 136
Actual return on plan assets	66	79
Purchases, sales, and settlements (net)	(29)	(54)
Transfers in and/or out of Level 3.....	—	—
Balance at end of period.....	<u>\$ 198</u>	<u>\$ 161</u>

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 to avoid a loss of 20% during any single year and to express 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 Wisser Pension Plan are set forth in the following table as of the dates indicated:

	December 31,			
	Forest Pension Plan		Wisser Pension Plan	
	2011	2010	2011	2010
Fixed income securities.....	22%	29%	21%	27%
Equity securities.....	76%	70%	78%	73%
Other	2%	1%	1%	0%
	<u>100%</u>	<u>100%</u>	<u>100%</u>	<u>100%</u>

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	
	2011	2010	2011	2010
	(In Thousands)			
Excess of benefit obligation over plan assets	\$ (18,798)	\$ (12,604)	\$ (13,498)	\$ (9,212)
Unrecognized actuarial loss (gain)	25,192	18,332	3,214	(431)
Net amount recognized	<u>\$ 6,394</u>	<u>\$ 5,728</u>	<u>\$ (10,284)</u>	<u>\$ (9,643)</u>
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—noncurrent	\$ (18,798)	\$ (12,604)	\$ (13,498)	\$ (9,212)
Accumulated other comprehensive income—net actuarial loss (gain)	25,192	18,332	3,214	(431)
Net amount recognized	<u>\$ 6,394</u>	<u>\$ 5,728</u>	<u>\$ (10,284)</u>	<u>\$ (9,643)</u>

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

	December 31,	
	2011	2010
	(In Thousands)	
Projected benefit obligation	\$ 44,755	\$ 42,213
Accumulated benefit obligation	44,755	42,213
Fair value of plan assets	25,957	29,609

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		
	2011	2010	2009	2011	2010	2009
	(Dollar Amounts In Thousands)					
Service cost	\$ —	\$ —	\$ —	\$ 825	\$ 668	\$ 543
Interest cost	1,836	2,005	2,207	529	430	415
Expected return on plan assets	(2,014)	(1,952)	(1,600)	—	—	—
Recognized actuarial loss (gain)	651	606	2,119	—	(40)	(132)
Total net periodic expense	<u>\$ 473</u>	<u>\$ 659</u>	<u>\$ 2,726</u>	<u>\$ 1,354</u>	<u>\$ 1,058</u>	<u>\$ 826</u>
Assumptions used to determine net periodic expense:						
Discount rate	<u>4.50%</u>	<u>5.04%</u>	<u>5.84%</u>	<u>5.15%</u>	<u>5.55%</u>	<u>6.12%</u>
Expected return on plan assets	<u>7%</u>	<u>7%</u>	<u>7%</u>	<u>n/a</u>	<u>n/a</u>	<u>n/a</u>
Assumptions used to determine benefit obligations:						
Discount rate	<u>3.58%</u>	<u>4.50%</u>	<u>5.04%</u>	<u>4.14%</u>	<u>5.15%</u>	<u>5.55%</u>

The discount rates used to determine benefit obligations were determined by adjusting the Moody's Aa Corporate bond yield 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 Moody's Aa index. 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, 2012, will include expense of \$.9 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive

income at December 31, 2011.

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, 2011	
	Postretirement Benefits Plan	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	\$ 378	\$ (278)
Effect on postretirement benefit obligation	2,993	(2,290)

Other Employee Benefit Plans

Forest sponsors various defined contribution plans in the United States under which the Company contributed matching contributions equal to \$3.7 million in 2011, \$3.3 million in 2010, and \$3.5 million in 2009.

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 2012 to maintain these life insurance policies is \$1.0 million. Forest recognized accretion expense related to the split dollar life insurance obligations of \$1.0 million, \$1.0 million, and \$1.4 million for the years ended December 31, 2011, 2010, and 2009, respectively. The discount rates used to determine the accretion expense were 4.08%, 4.01%, and 5.64% for the years ended December 31, 2011, 2010, and 2009, respectively. The split dollar life insurance obligation recognized in the balance sheet was \$7.3 million and \$7.3 million as of December 31, 2011 and 2010, respectively. The discount rates used to determine the obligations were 3.19% and 4.08% as of December 31, 2011 and 2010, respectively. The cash surrender value of the split dollar life insurance policies recognized in the balance sheets was \$3.6 million and \$3.3 million as of December 31, 2011 and 2010, respectively.

(8) FAIR VALUE MEASUREMENTS:

The Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2011 and 2010 are set forth by level within the fair value hierarchy in the table below.

Description	December 31,	
	2011	2010
	Using Significant Other Observable Inputs (Level 2) ⁽¹⁾	
	(In Thousands)	
Assets:		
Derivative instruments: ⁽²⁾		
Commodity	\$ 79,487	\$ 49,415
Interest rate	20,556	19,011
Total Assets	\$ 100,043	\$ 68,426
Liabilities:		
Derivative instruments: ⁽²⁾		
Commodity	\$ 28,944	\$ 36,413
Interest rate	—	—
Total Liabilities	\$ 28,944	\$ 36,413

(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 little or no market data exists, therefore requiring an entity to develop its own assumptions. The Company uses the income approach to value its derivative instruments under the Level 2 hierarchy.

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

The following table presents a reconciliation of the beginning and ending balances of the Company's assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2009. The Company did not have assets or liabilities with any fair value measured at fair value on a recurring basis using significant unobservable inputs (Level 3) at any time during 2011 or 2010.

	Year Ended December 31, 2009	
	Equity Securities	Debt Securities ⁽¹⁾
	(In Thousands)	
Balance at beginning of period	\$ —	\$ 1,670
Total net losses (realized/unrealized):		
Included in earnings	(657)	(1,670)
Included in other comprehensive income	—	—
Purchases, sales, issuances, and settlements:		
Purchases	—	—
Sales	—	—
Issuances	—	—
Settlements	—	—
Transfers in and/or out of Level 3 ⁽²⁾⁽³⁾	657	—
Balance at end of period	\$ —	\$ —
The amount of total losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at end of period	\$ (657)	\$ (1,670)

- (1) These debt securities consisted of a zero coupon senior subordinated note due from Pacific Energy Resources, Ltd. ("PERL") in 2014 at a principal amount at stated maturity of \$60.8 million (the "PERL Note") that was received as a portion of the total consideration for the sale of the Company's Alaska assets in 2007. In March 2009, PERL filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code and the court-approved Plan of Liquidation became effective in December 2010. During 2011, the Company affirmatively released any claim on the PERL Note. Prior to that, the Company used its own assumptions as to what market participants would assume regarding future cash flows and risk-adjusted discount rates in valuing the PERL Note, which had been valued at zero since March 31, 2009.
- (2) These equity securities consisted of shares of PERL common stock, which the Company also received as a portion of the total consideration for the sale of the Company's Alaska assets in 2007. The fair value measurement of the PERL common stock was transferred from Level 1 to Level 3 in the first quarter of 2009 when PERL's common stock was suspended from trading for failure to meet the continued stock exchange listing requirements. Prior to PERL's liquidation, under which common shareholders received no value for their PERL common stock, the Company used its own assumptions as to what market participants would assume regarding future cash flows and risk-adjusted discount rates in valuing the PERL common stock, which had been valued at zero since March 31, 2009.
- (3) The Company's policy is to recognize transfers in and/or out of fair value hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

The table below sets forth losses (realized and unrealized) included in earnings related to the Company's assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the period presented. These losses are reported in the Consolidated Statement of Operations in the "Other, net" line item. The Company did not record any gains or losses (realized and unrealized) related to assets or liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during 2011 or 2010.

	Year Ended December 31, 2009	
	Equity Securities	Debt Securities
	Other, net	Other, net
	(In Thousands)	
Total losses included in earnings for the period	\$ 657	\$ 1,670
Change in unrealized losses relating to assets still held at end of period	\$ 657	\$ 1,670

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

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value ⁽¹⁾	Carrying Amount	Fair Value ⁽¹⁾
(In Thousands)				
Assets:				
Cash and cash equivalents	\$ 3,012	\$ 3,012	\$ 217,569	\$ 217,569
Derivative instruments	100,043	100,043	68,426	68,426
Liabilities:				
Derivative instruments	28,944	28,944	36,413	36,413
Credit facility	105,000	105,000	—	—
8% senior notes due 2011	—	—	287,092	300,658
7% senior subordinated notes due 2013	12	12	12	12
8½% senior notes due 2014	587,611	653,250	581,790	660,000
7¼% senior notes due 2019	1,000,421	1,025,000	1,000,478	1,022,670

(1) The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amount of cash and cash equivalents approximated fair value due to the short original maturities (three months or less) and high liquidity of the cash equivalents. The carrying amount of the credit facility approximated fair value since borrowings bear interest at variable market rates. 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.

(9) DERIVATIVE INSTRUMENTS:

Commodity Derivatives

Forest periodically enters into commodity derivative instruments such as swap and collar agreements as an attempt to moderate the effects of wide fluctuations in commodity prices on Forest's cash flow and to manage the exposure to commodity price risk. Forest's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, Forest has elected not to designate its derivatives as hedging instruments for accounting purposes. As such, Forest recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the Consolidated Statement of Operations.

The table below sets forth Forest's outstanding commodity swaps as of December 31, 2011.

Term	Commodity Swaps					
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)		NGLs (OPIS Refined Products)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl	Barrels Per Day	Weighted Average Hedged Price per Bbl
Calendar 2012 ⁽¹⁾	105	\$ 5.30	—	\$ —	2,000	\$ 45.22
January 2012 - June 2012	—	—	5,000	98.24	—	—
July 2012 - December 2012	—	—	4,500	97.26	—	—

(1) During the fourth quarter of 2011, Forest entered into derivative agreements for the period April 2012 - December 2012 subjecting 50 Bbtu per day of the 2012 gas swaps to a written put of \$3.53 and a \$4.00 to \$4.50 call spread whereby Forest receives \$5.30 except as follows: Forest receives (i) NYMEX HH plus \$1.77 when NYMEX HH is below \$3.53; (ii) \$5.30 plus the value of the call spread when NYMEX HH is between \$4.00 and \$4.50; and (iii) \$5.80 when NYMEX HH is \$4.50 or above.

In connection with several natural gas and oil swaps entered into, Forest granted oil swaptions to the swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas and oil swaps. These swaptions grant the swap counterparties the option to enter into future swaps with Forest. The table below sets forth the outstanding swaptions as of December 31, 2011 (as of February 16, 2012, none of the swaptions in the table have been exercised by the counterparties).

Commodity Options

Instrument	Option Expiration	Underlying Swap Term	Oil (NYMEX WTI)	
			Underlying Swap Barrels Per Day	Underlying Swap Hedged Price per Bbl
Oil Swaptions	June 2012	July - December 2012	500	\$ 107.10
Oil Swaptions	December 2012	Calendar 2013	5,000	105.00

Derivative Instruments Entered Into Subsequent to December 31, 2011

Subsequent to December 31, 2011, through February 16, 2012, Forest entered into the following derivative agreements:

Commodity Swaps

Swap Term	Natural Gas (NYMEX HH)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu
April 2012 - December 2012 ⁽¹⁾	50	\$ 3.23
Calendar 2013 ⁽²⁾	80	4.02

- (1) In connection with entering into these natural gas swaps with premium hedged prices, Forest granted oil puts to the counterparties, giving the counterparties the option to put 5,000 barrels per day to Forest at \$75.00 per barrel on a monthly basis during April 2012 - December 2012.
- (2) In connection with entering into these natural gas swaps with premium hedged prices, Forest granted some of the counterparties with the option to enter into oil swaps with Forest for Calendar 2014 covering 3,000 barrels per day at a weighted average hedged price per barrel of \$109.67, with such options expiring in December 2013, and granted the other counterparties with the option to enter into natural gas swaps with Forest for Calendar 2013 covering 20 Bbtu per day at a weighted average hedged price per MMBtu of \$4.02, with such options expiring in December 2012.

Interest Rate Derivatives

Forest periodically enters into interest rate derivative instruments in an attempt to manage the mix of fixed and floating interest rates within its debt portfolio. The Company has elected not to designate its derivatives as hedging instruments. As such, the Company recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the Consolidated Statement of Operations. The table below sets forth Forest's outstanding fixed-to-floating interest rate swaps as of December 31, 2011.

Interest Rate Swaps			
Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate
January 2012 - February 2014.....	\$ 500,000	1 month LIBOR + 5.89%	8.50%

Fair Value and Gains and Losses

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

	December 31,	
	2011	2010
(In Thousands)		
Current assets:		
Commodity derivatives:		
Derivative instruments	\$ 79,487	\$ 49,415
Interest rate derivatives:		
Derivative instruments	10,134	10,767
Total current assets.....	<u>89,621</u>	<u>60,182</u>
Long-term assets:		
Interest rate derivatives:		
Derivative instruments	10,422	8,244
Total assets.....	<u>100,043</u>	<u>68,426</u>
Current liabilities:		
Commodity derivatives:		
Derivative instruments	28,944	36,413
Total liabilities	<u>28,944</u>	<u>36,413</u>
Net derivative fair value.....	<u>\$ 71,099</u>	<u>\$ 32,013</u>

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

	Year Ended December 31,		
	2011	2010	2009
(In Thousands)			
Commodity derivatives:			
Realized gains	\$ (37,535)	\$ (99,762)	\$ (297,208)
Unrealized (gains) losses	(37,542)	(18,390)	175,499
Interest rate derivatives:			
Realized gains	(11,442)	(12,450)	(10,958)
Unrealized (gains) losses	(1,545)	(19,530)	519
Realized and unrealized gains on derivative instruments, net	<u>\$ (88,064)</u>	<u>\$ (150,132)</u>	<u>\$ (132,148)</u>

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 in both the current period and prior periods and expects that volatility in commodity prices will continue.

Credit Risk

Forest executes with each of its derivative counterparties an International Swap and Derivatives Association, Inc. ("ISDA") Master Agreement, which is a standard industry form contract containing general terms and conditions applicable to many types of derivative transactions. Additionally, Forest executes, with each of its derivative counterparties a Schedule, which modifies the terms and conditions of the ISDA Master Agreement according to the parties' requirements and the specific types of derivatives to be traded. As of December 31, 2011, all of the 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 ISDA Master Agreements and Schedules contain cross-default provisions whereby a default under the Credit Facility will also cause a default under the derivative agreements. Such events of default include non-payment, breach of warranty, non-performance of the financial covenant, default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the Credit Facility. In addition, bankruptcy and insolvency events with respect to Forest or certain of its U.S. subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. None of these events of default is specifically credit-related, but some could arise if there were a general deterioration of Forest's credit. The ISDA Master Agreements and Schedules contain a further credit-related termination event that would occur if Forest were to merge with another entity and the creditworthiness of the resulting entity was materially weaker than that of Forest.

The derivative counterparties are all 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 \$77.5 million at December 31, 2011. 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, 2011, Forest owed a net derivative liability to three counterparties, the fair value of which was \$6.4 million. In the absence of netting provisions, at December 31, 2011, Forest would be exposed to a risk of loss of \$100.0 million under its derivative agreements and Forest's derivative counterparties would be exposed to a risk of loss of \$28.9 million.

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

(10) COMMITMENTS AND CONTINGENCIES:

The table below shows the Company's future rental payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2011.

	2012	2013	2014	2015	2016	After 2016	Total
	(In Thousands)						
Operating leases ⁽¹⁾	\$ 29,728	\$ 29,010	\$ 24,038	\$ 17,263	\$ 16,917	\$ 19,836	\$ 136,792
Unconditional purchase obligations ⁽²⁾ ..	1,673	851	—	—	—	—	2,524
	<u>\$ 31,401</u>	<u>\$ 29,861</u>	<u>\$ 24,038</u>	<u>\$ 17,263</u>	<u>\$ 16,917</u>	<u>\$ 19,836</u>	<u>\$ 139,316</u>

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

(2) Includes unconditional purchase obligations for throughput. Payments made under these unconditional purchase obligations were \$.5 million, in 2011, \$.4 million in 2010, and \$.2 million in 2009.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties approximated \$21.0 million in 2011, \$14.0 million in 2010, and \$10.1 million in 2009. Net rental payments under operating leases, including compressor rentals, charged to expense approximated \$16.5 million in 2011, \$18.4 million in 2010, and \$23.6 million in 2009. The Company has no leases that are accounted for as capital leases.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities ("PERL"). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL "abandoned" its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field ("Trading Bay"). At the

time of the abandonment of PERL's interests in Trading Bay, Union Oil Company of California ("Unocal") was the operator of those assets. On December 2, 2010, Unocal filed a lawsuit styled *Union Oil Company of California v. Forest Oil Corporation* in Anchorage District Court, Alaska. Forest has removed the case to federal district court in Anchorage, Alaska. In the lawsuit, the plaintiff complains about PERL's abandonment of Trading Bay and states that PERL has failed to pay approximately \$48.0 million in joint interest billings owed on those properties to date from the time PERL owned them. The plaintiff further claims that Forest is liable for PERL's share of all joint interest billings owed on Trading Bay, in arrears and in the future, because (1) Forest was the predecessor party to the contracts governing the operations at Trading Bay, (2) Unocal did not agree that, in conjunction with Forest's sale of its Alaska assets, Forest would be released of its obligations under the Trading Bay contracts, and (3) PERL has defaulted on the joint interest billings owed on Trading Bay since October 2008. As of December 31, 2011, Unocal sold its interest in the Trading Bay assets, including its claims against Forest, to Hilcorp Energy Company. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend to vigorously defend the action.

Forest, in the ordinary course of business, is a party to various other 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,		
	2011	2010	2009
	(In Thousands)		
Accretion of asset retirement obligations	\$ 6,082	\$ 6,158	\$ 7,302
Legal proceeding settlement.....	6,500	—	—
Gain on debt extinguishment, net.....	—	(4,576)	—
Other, net	4,582	5,757	18,824
	<u>\$ 17,164</u>	<u>\$ 7,339</u>	<u>\$ 26,126</u>

(12) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2011				
Oil, natural gas, and NGL sales:				
As reported ⁽¹⁾	\$ 202,571	\$ 237,848	\$ 174,012	\$ 176,616
Less: discontinued operations	36,261	51,255	—	—
Oil, natural gas, and NGL sales from continuing operations	<u>\$ 166,310</u>	<u>\$ 186,593</u>	<u>\$ 174,012</u>	<u>\$ 176,616</u>
Costs and expenses associated directly with products sold ⁽²⁾ :				
As reported ⁽¹⁾	\$ 118,465	\$ 126,479	\$ 89,343	\$ 105,377
Less: discontinued operations	31,325	34,873	—	—
Costs and expenses associated directly with products sold from continuing operations	<u>\$ 87,140</u>	<u>\$ 91,606</u>	<u>\$ 89,343</u>	<u>\$ 105,377</u>
Earnings (loss) before income taxes ⁽³⁾ :				
As reported ⁽¹⁾	\$ (5,047)	\$ 90,682	\$ 94,166	\$ 31,662
Less: discontinued operations	9,247	14,821	—	—
Earnings (loss) from continuing operations before income taxes	<u>\$ (14,294)</u>	<u>\$ 75,861</u>	<u>\$ 94,166</u>	<u>\$ 31,662</u>
Net earnings (loss) ⁽³⁾	<u>\$ (3,330)</u>	<u>\$ 38,974</u>	<u>\$ 87,718</u>	<u>\$ 19,467</u>
Net earnings (loss) attributable to Forest Oil ⁽³⁾⁽⁴⁾	\$ (3,330)	\$ 38,910	\$ 82,795	\$ 19,467
Basic earnings (loss) per share attributable to Forest Oil	\$ (.03)	\$.34	\$.72	\$.17
Diluted earnings (loss) per share attributable to Forest Oil	\$ (.03)	\$.34	\$.72	\$.17
2010				
Oil, natural gas, and NGL sales:				
As reported ⁽¹⁾	\$ 221,729	\$ 207,954	\$ 210,181	\$ 213,875
Less: discontinued operations	37,407	38,255	35,190	35,195
Oil, natural gas, and NGL sales from continuing operations	<u>\$ 184,322</u>	<u>\$ 169,699</u>	<u>\$ 174,991</u>	<u>\$ 178,680</u>
Costs and expenses associated directly with products sold ⁽²⁾ :				
As reported ⁽¹⁾	\$ 96,855	\$ 108,973	\$ 114,224	\$ 117,777
Less: discontinued operations	21,841	25,791	26,067	29,024
Costs and expenses associated directly with products sold from continuing operations	<u>\$ 75,014</u>	<u>\$ 83,182</u>	<u>\$ 88,157</u>	<u>\$ 88,753</u>
Earnings (loss) before income taxes ⁽³⁾ :				
As reported ⁽¹⁾	\$ 168,573	\$ 54,312	\$ 106,344	\$ 18,919
Less: discontinued operations	20,047	(282)	16,460	12,491
Earnings from continuing operations before income taxes	<u>\$ 148,526</u>	<u>\$ 54,594</u>	<u>\$ 89,884</u>	<u>\$ 6,428</u>
Net earnings ⁽³⁾	<u>\$ 109,162</u>	<u>\$ 33,254</u>	<u>\$ 68,911</u>	<u>\$ 16,194</u>
Net earnings attributable to Forest Oil ⁽³⁾⁽⁴⁾	\$ 109,162	\$ 33,254	\$ 68,911	\$ 16,194
Basic earnings per share attributable to Forest Oil	\$.97	\$.29	\$.61	\$.14
Diluted earnings per share attributable to Forest Oil	\$.97	\$.29	\$.60	\$.14

(1) Amounts shown for the first through third quarters of 2010 and first and second quarters of 2011 are those amounts that were previously reported in Forest's Quarterly Reports on Form 10-Q prior to the September 30, 2011 spin-off of Lone Pine, whose results are now reported as discontinued operations.

(2) 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.

(3) Earnings (loss) before income taxes, net earnings (loss), and net earnings (loss) attributable to Forest Oil have been subject to large fluctuations due to Forest's election not to use cash flow hedge accounting for derivative instruments as discussed in Note 9.

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

(13) DISCONTINUED OPERATIONS:

Since Lone Pine was a component of Forest with operations and cash flows clearly distinguishable both operationally and for financial reporting purposes from those of Forest, and because Lone Pine's operations and cash flows have been eliminated from the ongoing operations of Forest and Forest will not have any significant continuing involvement in the operations of Lone Pine, Forest has presented Lone Pine's results of operations as discontinued operations in the Consolidated Statements of Operations for the periods presented. Additionally, Forest has separately presented Lone Pine's assets and liabilities in the Consolidated Balance Sheet as of December 31, 2010. Lone Pine's assets and liabilities are not presented in Forest's Consolidated Balance Sheet as of December 31, 2011 due to the spin-off occurring on September 30, 2011. For more information regarding the spin-off see Note 5.

The table below presents the major classes of assets and liabilities included in the discontinued operations classifications within the Consolidated Balance Sheet as of December 31, 2010.

	December 31, 2010
	(In Thousands)
Cash.....	\$ 576
Accounts receivable	33,405
Other current assets	16,161
Current assets of discontinued operations	<u>\$ 50,142</u>
Property and equipment, at cost:	
Oil and gas properties, full cost method of accounting:	
Proved, net of accumulated depletion of \$1,125,482	\$ 479,595
Unproved	105,520
Net oil and gas properties	<u>585,115</u>
Other property and equipment, net of accumulated depreciation and amortization of \$8,059.....	60,290
Net property and equipment.....	<u>645,405</u>
Goodwill.....	17,422
Other assets	2,222
Long-term assets of discontinued operations	<u>\$ 665,049</u>
Accounts payable and accrued liabilities	\$ 42,202
Other current liabilities.....	3,445
Current liabilities of discontinued operations	<u>\$ 45,647</u>
Deferred income taxes.....	57,560
Asset retirement obligations.....	13,741
Other long-term liabilities	3,172
Long-term liabilities of discontinued operations	<u>\$ 74,473</u>

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

	Nine Months Ended September 30,	Year Ended December 31,	
	2011	2010	2009
	(In Thousands)		
Total revenues.....	\$ 137,834	\$ 146,070	\$ 112,076
Production expenses.....	40,350	38,841	38,321
General and administrative.....	8,846	8,318	5,822
Depreciation, depletion, and amortization.....	60,780	63,645	56,464
Ceiling test write-down of oil and gas properties.....	—	—	199,021
Interest expense.....	3,866	381	2,357
Realized and unrealized gains on derivative instruments, net.....	(33,628)	—	—
Realized foreign currency exchange gains.....	(33,869)	(270)	(88)
Unrealized foreign currency exchange losses (gains), net.....	28,488	(14,290)	(17,974)
Other, net.....	1,328	729	1,371
Earnings (loss) from discontinued operations before tax.....	61,673	48,716	(173,218)
Income tax.....	17,104	10,857	(43,874)
Net earnings (loss) from discontinued operations.....	<u>\$ 44,569</u>	<u>\$ 37,859</u>	<u>\$ (129,344)</u>

(14) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

The Company's 8½% senior notes due 2014 and 7¼% senior notes due 2019 have been fully and unconditionally guaranteed by a wholly-owned subsidiary of the Company (the "Guarantor Subsidiary"). The Company's remaining subsidiaries (the "Non-Guarantor Subsidiaries") have not provided guarantees. Based on this distinction, the following presents condensed consolidating financial information as of December 31, 2011 and 2010, and for the three years in the period ended December 31, 2011 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiaries, eliminating entries, and consolidated basis. Eliminating entries presented are necessary to combine the entities.

CONDENSED CONSOLIDATING BALANCE SHEETS
(In Thousands)

	December 31, 2011				
ASSETS	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current assets:					
Cash and cash equivalents.....	\$ 1,734	\$ 1	\$ 1,277	\$ —	\$ 3,012
Accounts receivable	43,999	34,142	2,201	(1,253)	79,089
Other current assets	127,667	313	591	—	128,571
Total current assets	173,400	34,456	4,069	(1,253)	210,672
Property and equipment, at cost	8,000,466	1,317,917	282,719	—	9,601,102
Less accumulated depreciation, depletion, and amortization	5,782,409	1,102,339	65,238	—	6,949,986
Net property and equipment	2,218,057	215,578	217,481	—	2,651,116
Investment in subsidiaries	160,591	—	—	(160,591)	—
Goodwill	216,460	22,960	—	—	239,420
Due from subsidiaries	214,394	46,944	—	(261,338)	—
Deferred income taxes	312,564	—	25,564	(107,012)	231,116
Other assets	48,827	—	—	—	48,827
	<u>\$ 3,344,293</u>	<u>\$ 319,938</u>	<u>\$ 247,114</u>	<u>\$ (530,194)</u>	<u>\$ 3,381,151</u>
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable and accrued liabilities	\$ 235,788	\$ 8,846	\$ 4,499	\$ (1,253)	\$ 247,880
Other current liabilities	86,618	63	6,276	—	92,957
Total current liabilities	322,406	8,909	10,775	(1,253)	340,837
Long-term debt	1,693,044	—	—	—	1,693,044
Due to parent and subsidiaries	—	—	261,338	(261,338)	—
Deferred income taxes	—	107,012	—	(107,012)	—
Other liabilities	135,730	2,614	15,813	—	154,157
Total liabilities	2,151,180	118,535	287,926	(369,603)	2,188,038
Shareholders' equity	1,193,113	201,403	(40,812)	(160,591)	1,193,113
	<u>\$ 3,344,293</u>	<u>\$ 319,938</u>	<u>\$ 247,114</u>	<u>\$ (530,194)</u>	<u>\$ 3,381,151</u>

CONDENSED CONSOLIDATING BALANCE SHEETS (Continued)
(In Thousands)

	December 31, 2010				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents.....	\$ 216,580	\$ 3	\$ 986	\$ —	\$ 217,569
Accounts receivable	50,024	50,211	2,886	(796)	102,325
Note receivable from subsidiary	250,183	—	—	(250,183)	—
Other current assets	110,766	755	126	—	111,647
Current assets of discontinued operations.....	—	—	50,142	—	50,142
Total current assets	627,553	50,969	54,140	(250,979)	481,683
Property and equipment, at cost	7,403,398	1,198,138	199,181	—	8,800,717
Less accumulated depreciation, depletion, and amortization	5,618,604	1,049,647	62,193	—	6,730,444
Net property and equipment	1,784,794	148,491	136,988	—	2,070,273
Investment in subsidiaries	435,062	—	—	(435,062)	—
Goodwill.....	216,460	22,960	—	—	239,420
Due from subsidiaries.....	190,635	—	—	(190,635)	—
Deferred income taxes	330,309	—	21,654	(67,942)	284,021
Other assets.....	44,936	6	—	—	44,942
Long-term assets of discontinued operations	—	—	665,049	—	665,049
	<u>\$ 3,629,749</u>	<u>\$ 222,426</u>	<u>\$ 877,831</u>	<u>\$ (944,618)</u>	<u>\$ 3,785,388</u>
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable and accrued liabilities	\$ 204,295	\$ 2,189	\$ 4,310	\$ (796)	\$ 209,998
Current portion of long-term debt.....	287,092	—	—	—	287,092
Other current liabilities	80,328	36	6,273	—	86,637
Current liabilities of discontinued operations	—	—	295,830	(250,183)	45,647
Total current liabilities.....	571,715	2,225	306,413	(250,979)	629,374
Long-term debt	1,582,280	—	—	—	1,582,280
Due to parent	—	13,388	177,247	(190,635)	—
Deferred income taxes	577	67,365	—	(67,942)	—
Other liabilities	122,390	2,119	21,965	—	146,474
Long-term liabilities of discontinued operations.....	—	—	74,473	—	74,473
Total liabilities	2,276,962	85,097	580,098	(509,556)	2,432,601
Shareholders' equity	1,352,787	137,329	297,733	(435,062)	1,352,787
	<u>\$ 3,629,749</u>	<u>\$ 222,426</u>	<u>\$ 877,831</u>	<u>\$ (944,618)</u>	<u>\$ 3,785,388</u>

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In Thousands)

	Year Ended December 31, 2011				
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil, natural gas, and NGL sales.....	\$ 517,649	\$ 183,391	\$ 2,491	\$ —	\$ 703,531
Interest and other.....	3,569	5,834	—	(8,377)	1,026
Equity earnings in subsidiaries.....	102,237	—	—	(102,237)	—
Total revenues.....	<u>623,455</u>	<u>189,225</u>	<u>2,491</u>	<u>(110,614)</u>	<u>704,557</u>
Costs, expenses, and other:					
Lease operating expenses.....	84,117	14,620	421	—	99,158
Other production expenses.....	47,066	7,122	172	—	54,360
General and administrative.....	60,855	2,787	1,463	—	65,105
Depreciation, depletion, and amortization.....	165,270	52,692	1,722	—	219,684
Interest expense.....	149,755	4,949	3,428	(8,377)	149,755
Realized and unrealized (gains) losses on derivative instruments, net.....	(91,221)	3,192	(35)	—	(88,064)
Other, net.....	11,386	238	5,540	—	17,164
Total costs, expenses, and other.....	<u>427,228</u>	<u>85,600</u>	<u>12,711</u>	<u>(8,377)</u>	<u>517,162</u>
Earnings (loss) from continuing operations before income taxes.....	196,227	103,625	(10,220)	(102,237)	187,395
Income tax.....	53,398	39,647	(3,910)	—	89,135
Net earnings (loss) from continuing operations.....	<u>142,829</u>	<u>63,978</u>	<u>(6,310)</u>	<u>(102,237)</u>	<u>98,260</u>
Net earnings from discontinued operations.....	—	—	44,569	—	44,569
Net earnings.....	<u>142,829</u>	<u>63,978</u>	<u>38,259</u>	<u>(102,237)</u>	<u>142,829</u>
Less: net earnings attributable to noncontrolling interest.....	—	—	4,987	—	4,987
Net earnings attributable to Forest Oil Corporation.....	<u>\$ 142,829</u>	<u>\$ 63,978</u>	<u>\$ 33,272</u>	<u>\$ (102,237)</u>	<u>\$ 137,842</u>

	Year Ended December 31, 2010				
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil, natural gas, and NGL sales.....	\$ 479,250	\$ 225,937	\$ 2,505	\$ —	\$ 707,692
Interest and other.....	5,504	32	—	(4,547)	989
Equity earnings in subsidiaries.....	140,064	—	—	(140,064)	—
Total revenues.....	<u>624,818</u>	<u>225,969</u>	<u>2,505</u>	<u>(144,611)</u>	<u>708,681</u>
Costs, expenses, and other:					
Lease operating expenses.....	79,927	11,974	493	—	92,394
Other production expenses.....	45,318	11,454	126	—	56,898
General and administrative.....	60,901	2,408	1,577	—	64,886
Depreciation, depletion, and amortization.....	130,777	55,642	1,554	—	187,973
Interest expense.....	149,891	1,381	3,166	(4,547)	149,891
Realized and unrealized gains on derivative instruments, net.....	(122,389)	(27,457)	(286)	—	(150,132)
Other, net.....	877	(456)	6,918	—	7,339
Total costs, expenses, and other.....	<u>345,302</u>	<u>54,946</u>	<u>13,548</u>	<u>(4,547)</u>	<u>409,249</u>
Earnings (loss) from continuing operations before income taxes.....	279,516	171,023	(11,043)	(140,064)	299,432
Income tax.....	50,285	62,919	(3,434)	—	109,770
Net earnings (loss) from continuing operations.....	<u>229,231</u>	<u>108,104</u>	<u>(7,609)</u>	<u>(140,064)</u>	<u>189,662</u>
Net earnings from discontinued operations.....	—	—	37,859	—	37,859
Net earnings.....	<u>\$ 229,231</u>	<u>\$ 108,104</u>	<u>\$ 30,250</u>	<u>\$ (140,064)</u>	<u>\$ 227,521</u>

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS (Continued)
(In Thousands)

	Year Ended December 31, 2009				
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil, natural gas, and NGL sales.....	\$ 520,792	\$ 132,644	\$ 2,143	\$ —	\$ 655,579
Interest and other	17,666	92	1	(16,959)	800
Equity earnings in subsidiaries.....	(235,174)	—	—	235,174	—
Total revenues.....	<u>303,284</u>	<u>132,736</u>	<u>2,144</u>	<u>218,215</u>	<u>656,379</u>
Costs, expenses, and other:					
Lease operating expenses	99,459	19,259	754	—	119,472
Other production expenses	46,828	6,023	151	—	53,002
General and administrative.....	61,532	2,506	1,216	—	65,254
Depreciation, depletion, and amortization	197,501	47,637	2,020	—	247,158
Ceiling test write-down of oil and gas properties.....	1,155,777	218,567	2,478	—	1,376,822
Interest expense	161,083	12,256	4,299	(16,555)	161,083
Realized and unrealized gains on derivative instruments, net.....	(111,765)	(20,062)	(321)	—	(132,148)
Other, net	18,433	260	7,433	—	26,126
Total costs, expenses, and other	<u>1,628,848</u>	<u>286,446</u>	<u>18,030</u>	<u>(16,555)</u>	<u>1,916,769</u>
Earnings (loss) from continuing operations before income taxes	(1,325,564)	(153,710)	(15,886)	234,770	(1,260,390)
Income tax	(404,573)	(56,937)	(5,091)	—	(466,601)
Net earnings (loss) from continuing operations	(920,991)	(96,773)	(10,795)	234,770	(793,789)
Net earnings (loss) from discontinued operations	—	—	(129,344)	—	(129,344)
Net earnings (loss).....	<u>\$ (920,991)</u>	<u>\$ (96,773)</u>	<u>\$ (140,139)</u>	<u>\$ 234,770</u>	<u>\$ (923,133)</u>

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2011			
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Consolidated
Operating activities:				
Net earnings	\$ 40,592	\$ 63,978	\$ 38,259	\$ 142,829
Less: net earnings from discontinued operations	—	—	44,569	44,569
Net earnings (loss) from continuing operations	40,592	63,978	(6,310)	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	165,270	52,692	1,722	219,684
Deferred income tax	23,257	39,647	(3,910)	58,994
Unrealized (gains) losses on derivative instruments, net	(40,666)	1,596	(17)	(39,087)
Other, net	36,714	331	(2,313)	34,732
Changes in operating assets and liabilities:				
Accounts receivable	6,025	16,069	1,142	23,236
Other current assets	12,816	442	1,056	14,314
Accounts payable and accrued liabilities	(7,894)	1,564	(140)	(6,470)
Accrued interest and other current liabilities	(5,165)	(252)	(149)	(5,566)
Net cash provided (used) by operating activities of continuing operations	230,949	176,067	(8,919)	398,097
Investing activities:				
Capital expenditures for property and equipment	(683,758)	(114,715)	(82,372)	(880,845)
Proceeds from sales of assets	120,992	—	123	121,115
Net cash used by investing activities of continuing operations	(562,766)	(114,715)	(82,249)	(759,730)
Financing activities:				
Proceeds from bank borrowings	160,000	—	—	160,000
Repayments of bank borrowings	(55,000)	—	—	(55,000)
Redemption of senior notes	(285,000)	—	—	(285,000)
Change in bank overdrafts	16,682	478	(44)	17,116
Net activity in investments in subsidiaries	290,710	(61,832)	(228,878)	—
Other, net	(10,421)	—	—	(10,421)
Net cash provided (used) by financing activities of continuing operations	116,971	(61,354)	(228,922)	(173,305)
Cash flows of discontinued operations:				
Operating cash flows	—	—	101,292	101,292
Investing cash flows	—	—	(255,470)	(255,470)
Financing cash flows	—	—	478,324	478,324
Net cash provided by discontinued operations	—	—	324,146	324,146
Effect of exchange rate changes on cash	—	—	(3,476)	(3,476)
Net (decrease) increase in cash and cash equivalents	(214,846)	(2)	580	(214,268)
Net increase in cash and cash equivalents of discontinued operations	—	—	(289)	(289)
Net (decrease) increase in cash and cash equivalents of continuing operations	(214,846)	(2)	291	(214,557)
Cash and cash equivalents of continuing operations at beginning of period	216,580	3	986	217,569
Cash and cash equivalents of continuing operations at end of period	\$ 1,734	\$ 1	\$ 1,277	\$ 3,012

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Continued)
(In Thousands)

	Year Ended December 31, 2010			
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Consolidated
Operating activities:				
Net earnings	\$ 89,167	\$ 108,104	\$ 30,250	\$ 227,521
Less: net earnings from discontinued operations	—	—	37,859	37,859
Net earnings (loss) from continuing operations	89,167	108,104	(7,609)	189,662
Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations:				
Depreciation, depletion, and amortization	130,777	55,642	1,554	187,973
Deferred income tax	64,185	62,919	(3,433)	123,671
Unrealized gains on derivative instruments, net	(33,602)	(4,274)	(44)	(37,920)
Other, net	29,936	263	(3,435)	26,764
Changes in operating assets and liabilities:				
Accounts receivable	29,833	(25,805)	(1,388)	2,640
Other current assets	22,818	42	1,276	24,136
Accounts payable and accrued liabilities	(60,768)	(2,557)	890	(62,435)
Accrued interest and other current liabilities	(17,023)	(191)	9,448	(7,766)
Net cash provided (used) by operating activities of continuing operations	255,323	194,143	(2,741)	446,725
Investing activities:				
Capital expenditures for property and equipment	(432,484)	(121,458)	(8,189)	(562,131)
Proceeds from sales of assets	140,643	(1,565)	(1)	139,077
Net cash used by investing activities of continuing operations	(291,841)	(123,023)	(8,190)	(423,054)
Financing activities:				
Redemption of senior notes	(152,038)	—	—	(152,038)
Change in bank overdrafts	7,834	(1,334)	(122)	6,378
Net activity in investments in subsidiaries	(63,126)	(70,162)	133,288	—
Other, net	3,450	—	(1)	3,449
Net cash (used) provided by financing activities of continuing operations	(203,880)	(71,496)	133,165	(142,211)
Cash flows of discontinued operations:				
Operating cash flows	—	—	86,204	86,204
Investing cash flows	—	—	(218,155)	(218,155)
Financing cash flows	—	—	1,692	1,692
Net cash used by discontinued operations	—	—	(130,259)	(130,259)
Effect of exchange rate changes on cash	—	—	(277)	(277)
Net decrease in cash and cash equivalents	(240,398)	(376)	(8,302)	(249,076)
Net decrease in cash and cash equivalents of discontinued operations	—	—	8,370	8,370
Net (decrease) increase in cash and cash equivalents of continuing operations	(240,398)	(376)	68	(240,706)
Cash and cash equivalents of continuing operations at beginning of period	456,978	379	918	458,275
Cash and cash equivalents of continuing operations at end of period	<u>\$ 216,580</u>	<u>\$ 3</u>	<u>\$ 986</u>	<u>\$ 217,569</u>

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Continued)
(In Thousands)

	Year Ended December 31, 2009			
	Parent Company	Guarantor Subsidiary	Combined Non- Guarantor Subsidiaries	Consolidated
Operating activities:				
Net earnings (loss)	\$ (685,817)	\$ (96,773)	\$ (140,543)	\$ (923,133)
Less: net earnings (loss) from discontinued operations	—	—	(129,344)	(129,344)
Net earnings (loss) from continuing operations	(685,817)	(96,773)	(11,199)	(793,789)
Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations:				
Depreciation, depletion, and amortization	197,501	47,637	2,020	247,158
Deferred income tax	(475,388)	(56,937)	(5,091)	(537,416)
Unrealized losses on derivative instruments, net	146,628	28,929	461	176,018
Ceiling test write-down of oil and gas properties	1,155,777	218,567	2,478	1,376,822
Other, net	33,387	334	(2,539)	31,182
Changes in operating assets and liabilities:				
Accounts receivable	27,084	(2,403)	1,941	26,622
Other current assets	34,239	(364)	(634)	33,241
Accounts payable and accrued liabilities	(22,322)	(7,984)	(6,514)	(36,820)
Accrued interest and other current liabilities	15,344	(1,571)	(417)	13,356
Net cash provided (used) by operating activities of continuing operations	426,433	129,435	(19,494)	536,374
Investing activities:				
Capital expenditures for property and equipment	(456,959)	(104,218)	(15,454)	(576,631)
Proceeds from sales of assets	657,247	276,211	34	933,492
Other, net	27	—	1	28
Net cash provided (used) by investing activities of continuing operations	200,315	171,993	(15,419)	356,889
Financing activities:				
Proceeds from bank borrowings	747,000	—	—	747,000
Repayments of bank borrowings	(1,937,000)	—	—	(1,937,000)
Issuance of senior notes, net of issuance costs	559,767	—	—	559,767
Proceeds from common stock offering, net of offering costs	256,217	—	—	256,217
Redemption of senior notes	(970)	—	—	(970)
Change in bank overdrafts	(35,466)	(3,119)	(358)	(38,943)
Net activity in investments in subsidiaries	226,726	(298,004)	71,278	—
Other, net	12,730	—	—	12,730
Net cash (used) provided by financing activities of continuing operations	(170,996)	(301,123)	70,920	(401,199)
Cash flows of discontinued operations:				
Operating cash flows	—	—	60,622	60,622
Investing cash flows	—	—	28,483	28,483
Financing cash flows	—	—	(115,665)	(115,665)
Net cash used by discontinued operations	—	—	(26,560)	(26,560)
Effect of exchange rate changes on cash	—	—	(488)	(488)
Net increase in cash and cash equivalents	455,752	305	8,959	465,016
Net increase in cash and cash equivalents of discontinued operations	—	—	(8,946)	(8,946)
Net increase in cash and cash equivalents of continuing operations	455,752	305	13	456,070
Cash and cash equivalents of continuing operations at beginning of period	1,226	74	905	2,205
Cash and cash equivalents of continuing operations at end of period	\$ 456,978	\$ 379	\$ 918	\$ 458,275

(15) 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 Oil and Gas Reserves

The reserve estimates as of December 31, 2011, 2010 and 2009 presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the Financial Accounting Standards Board effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's "Modernization of Oil and Gas Reporting" rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

Proved oil and gas reserves are those 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. Existing economic conditions include the average prices for oil and gas during the twelve month period before the reporting date, 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 oil and gas 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 oil and gas 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 and gas reserves as of December 31, 2011, 2010, and 2009 and changes in its net proved oil and gas 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			Natural Gas Liquids			Natural Gas			
	(MBbls)			(MBbls)			(MMcf)			
	United States	Italy	Total	United States	Italy	Total	United States	Italy	Total	Total MMcfe
Balance at January 1, 2009	50,185	—	50,185	50,099	—	50,099	1,719,583	56,308	1,775,891	2,377,595
Revisions of previous estimates.....	1,596	—	1,596	(5,229)	—	(5,229)	(357,352)	(4,570)	(361,922)	(383,720)
Extensions and discoveries	22,324	—	22,324	9,156	—	9,156	320,705	—	320,705	509,585
Production	(3,397)	—	(3,397)	(3,012)	—	(3,012)	(116,029)	—	(116,029)	(154,483)
Sales of reserves in place	(53,776)	—	(53,776)	(12,778)	—	(12,778)	(151,476)	—	(151,476)	(550,800)
Purchases of reserves in place.....	—	—	—	—	—	—	—	—	—	—
Balance at December 31, 2009	16,932	—	16,932	38,236	—	38,236	1,415,431	51,738	1,467,169	1,798,177
Revisions of previous estimates.....	1,276	—	1,276	(278)	—	(278)	(38,515)	—	(38,515)	(32,527)
Extensions and discoveries	4,591	—	4,591	9,051	—	9,051	199,790	—	199,790	281,642
Production	(2,357)	—	(2,357)	(3,589)	—	(3,589)	(101,346)	—	(101,346)	(137,022)
Sales of reserves in place	(183)	—	(183)	(292)	—	(292)	(45,783)	—	(45,783)	(48,633)
Purchases of reserves in place.....	59	—	59	256	—	256	4,154	—	4,154	6,044
Balance at December 31, 2010	20,318	—	20,318	43,384	—	43,384	1,433,731	51,738	1,485,469	1,867,681
Revisions of previous estimates.....	(1,061)	—	(1,061)	(3,716)	—	(3,716)	(91,721)	—	(91,721)	(120,383)
Extensions and discoveries	17,816	—	17,816	8,262	—	8,262	144,094	—	144,094	300,562
Production	(2,491)	—	(2,491)	(3,154)	—	(3,154)	(88,497)	—	(88,497)	(122,367)
Sales of reserves in place	(2,989)	—	(2,989)	(347)	—	(347)	(1,091)	—	(1,091)	(21,107)
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
Proved developed reserves at:										
January 1, 2009	34,298	—	34,298	29,716	—	29,716	1,039,586	28,154	1,067,740	1,451,824
December 31, 2009	11,327	—	11,327	23,037	—	23,037	916,005	—	916,005	1,122,189
December 31, 2010	13,421	—	13,421	24,120	—	24,120	886,644	25,869	912,513	1,137,759
December 31, 2011	14,149	—	14,149	23,170	—	23,170	814,160	—	814,160	1,038,074
Proved undeveloped reserves at:										
January 1, 2009	15,887	—	15,887	20,383	—	20,383	679,997	28,154	708,151	925,771
December 31, 2009	5,605	—	5,605	15,199	—	15,199	499,426	51,738	551,164	675,988
December 31, 2010	6,897	—	6,897	19,264	—	19,264	547,087	25,869	572,956	729,922
December 31, 2011	17,444	—	17,444	21,259	—	21,259	582,356	51,738	634,094	866,312

Revisions of previous estimates

In 2011, net negative revisions of 120 Bcfe were primarily a result of the write-off of proved undeveloped locations ("PUD") pursuant to the SEC's five year limitation on PUDs and the write-off of gas reserves associated with a deep gas project in South Louisiana. In 2010, the net negative revisions of 33 Bcfe were primarily the result of performance in existing producing wells. In 2009, the net negative revisions of 384 Bcfe were due to a decrease in the natural gas price used to estimate reserve volumes for that period.

Extensions and discoveries

In 2011, the Company had 301 Bcfe of extensions and discoveries, which were primarily due to successful drilling results in the Texas Panhandle and South Texas. In 2010, the Company had 282 Bcfe of extensions and discoveries, which were primarily due to successful drilling results in the Texas Panhandle and North Louisiana. In 2009, the Company had 510 Bcfe of extensions and discoveries, which were primarily due to successful drilling results in the Texas Panhandle and East Texas / North Louisiana.

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 gas property interests. See Note 2 for a description of these sales.

Aggregate Capitalized Costs

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

	December 31,	
	2011	2010
	(In Thousands)	
Costs related to proved properties.....	\$ 8,825,142	\$ 8,058,876
Costs related to unproved properties.....	675,995	646,264
	9,501,137	8,705,140
Less accumulated depletion	(6,901,997)	(6,688,012)
	<u>\$ 2,599,140</u>	<u>\$ 2,017,128</u>

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, 2011, 2010, and 2009:

	United States	Italy	Total
	(In Thousands)		
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⁾	<u>\$ 908,365</u>	<u>\$ 1,369</u>	<u>\$ 909,734</u>
2010			
Property acquisition costs:			
Proved properties.....	\$ 5,823	\$ —	\$ 5,823
Unproved properties	64,593	—	64,593
Exploration costs.....	190,553	2,386	192,939
Development costs	319,510	317	319,827
Total costs incurred ⁽¹⁾	<u>\$ 580,479</u>	<u>\$ 2,703</u>	<u>\$ 583,182</u>
2009			
Property acquisition costs:			
Proved properties.....	\$ —	\$ —	\$ —
Unproved properties	45,230	—	45,230
Exploration costs.....	112,919	7,578	120,497
Development costs	339,826	—	339,826
Total costs incurred ⁽¹⁾	<u>\$ 497,975</u>	<u>\$ 7,578</u>	<u>\$ 505,553</u>

(1) Includes amounts relating to changes in estimated asset retirement obligations of \$3.1 million, \$(1.1) million, and \$1.1 million recorded during the years ended December 31, 2011, 2010, and 2009, 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, 2011, 2010, and 2009 are presented below.

	United States	Italy	Total
	(In Thousands, except per Mcfe amounts)		
2011			
Oil and gas 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	89,135	—	89,135
Total expenses	<u>462,492</u>	<u>44</u>	<u>462,536</u>
Results of operations from oil and gas producing activities	<u>\$ 241,039</u>	<u>\$ (44)</u>	<u>\$ 240,995</u>
Depletion rate per Mcfe	<u>\$ 1.75</u>	<u>\$ —</u>	<u>\$ 1.75</u>
2010			
Oil and gas sales.....	\$ 707,692	\$ —	\$ 707,692
Expenses:			
Production expense.....	149,292	—	149,292
Depletion expense.....	179,656	—	179,656
Accretion of asset retirement obligations	6,057	41	6,098
Income tax expense.....	134,801	—	134,801
Total expenses	<u>469,806</u>	<u>41</u>	<u>469,847</u>
Results of operations from oil and gas producing activities	<u>\$ 237,886</u>	<u>\$ (41)</u>	<u>\$ 237,845</u>
Depletion rate per Mcfe	<u>\$ 1.31</u>	<u>\$ —</u>	<u>\$ 1.31</u>
2009			
Oil and gas sales.....	\$ 655,579	\$ —	\$ 655,579
Expenses:			
Production expense.....	172,474	—	172,474
Depletion expense.....	235,994	—	235,994
Ceiling test write-down of oil and gas properties.....	1,376,822	—	1,376,822
Accretion of asset retirement obligations	7,206	38	7,244
Income tax expense.....	(410,997)	—	(410,997)
Total expenses	<u>1,381,499</u>	<u>38</u>	<u>1,381,537</u>
Results of operations from oil and gas producing activities	<u>\$ (725,920)</u>	<u>\$ (38)</u>	<u>\$ (725,958)</u>
Depletion rate per Mcfe	<u>\$ 1.53</u>	<u>\$ —</u>	<u>\$ 1.53</u>

Standardized Measure of Discounted Future Net Cash Flows

Future oil and gas sales are calculated applying the prices used in estimating the Company's estimated proved oil and gas 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 oil and gas 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 oil and gas 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 oil and gas reserves. All cash flow amounts, including income taxes, are discounted at 10%.

Changes in the demand for oil and natural gas, 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, 2011		
	United States	Italy	Total
	(In Thousands)		
Future oil and gas 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.....	<u>\$ 2,285,742</u>	<u>\$ 101,999</u>	<u>\$ 2,387,741</u>

	December 31, 2010		
	United States	Italy	Total
	(In Thousands)		
Future oil and gas sales.....	\$ 9,029,839	\$ 904,902	\$ 9,934,741
Future production costs.....	(2,546,332)	(192,013)	(2,738,345)
Future development costs.....	(1,462,832)	(17,100)	(1,479,932)
Future income taxes.....	(860,047)	(260,541)	(1,120,588)
Future net cash flows.....	4,160,628	435,248	4,595,876
10% annual discount for estimated timing of cash flows.....	(2,195,708)	(229,722)	(2,425,430)
Standardized measure of discounted future net cash flows.....	<u>\$ 1,964,920</u>	<u>\$ 205,526</u>	<u>\$ 2,170,446</u>

	December 31, 2009		
	United States	Italy	Total
	(In Thousands)		
Future oil and gas sales.....	\$ 6,632,073	\$ 797,286	\$ 7,429,359
Future production costs.....	(2,076,453)	(77,679)	(2,154,132)
Future development costs.....	(1,225,330)	(55,397)	(1,280,727)
Future income taxes.....	(264,263)	(245,394)	(509,657)
Future net cash flows.....	3,066,027	418,816	3,484,843
10% annual discount for estimated timing of cash flows.....	(1,737,138)	(193,396)	(1,930,534)
Standardized measure of discounted future net cash flows.....	<u>\$ 1,328,889</u>	<u>\$ 225,420</u>	<u>\$ 1,554,309</u>

Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas 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, 2011		
	United States	Italy	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	\$ 1,964,920	\$ 205,526	\$ 2,170,446
Changes resulting from:			
Sales of oil and gas, 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	<u>320,822</u>	<u>(103,527)</u>	<u>217,295</u>
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	<u>\$ 2,285,742</u>	<u>\$ 101,999</u>	<u>\$ 2,387,741</u>

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas 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.

	December 31, 2010		
	United States	Italy	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	\$ 1,328,889	\$ 225,420	\$ 1,554,309
Changes resulting from:			
Sales of oil and gas, net of production costs	(558,400)	—	(558,400)
Net changes in prices and future production costs	603,003	2,040	605,043
Net changes in future development costs	(29,183)	17,586	(11,597)
Extensions, discoveries, and improved recovery	445,546	—	445,546
Development costs incurred during the period	134,451	—	134,451
Revisions of previous quantity estimates	48,960	—	48,960
Changes in production rates, timing, and other	115,768	(65,068)	50,700
Sales of reserves in place	(34,108)	—	(34,108)
Purchases of reserves in place	6,530	—	6,530
Accretion of discount on reserves at beginning of year	139,179	33,175	172,354
Net change in income taxes	(235,715)	(7,627)	(243,342)
Total change for year	<u>636,031</u>	<u>(19,894)</u>	<u>616,137</u>
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	<u>\$ 1,964,920</u>	<u>\$ 205,526</u>	<u>\$ 2,170,446</u>

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2010 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, 2010 were \$4.38 per MMBtu and \$79.81 per barrel, respectively.

	December 31, 2009		
	United States	Italy	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	\$ 2,428,679	\$ 378,426	\$ 2,807,105
Changes resulting from:			
Sales of oil and gas, net of production costs	(483,096)	—	(483,096)
Net changes in prices and future production costs	(772,932)	(125,096)	(898,028)
Net changes in future development costs	(30,921)	(9,155)	(40,076)
Extensions, discoveries, and improved recovery	624,014	—	624,014
Development costs incurred during the period	38,353	—	38,353
Revisions of previous quantity estimates	(44,548)	(31,749)	(76,297)
Changes in production rates, timing, and other	(49,773)	(121,135)	(170,908)
Sales of reserves in place	(933,591)	—	(933,591)
Purchases of reserves in place	—	—	—
Accretion of discount on reserves at beginning of year	276,753	56,263	333,016
Net change in income taxes	275,951	77,866	353,817
Total change for year	<u>(1,099,790)</u>	<u>(153,006)</u>	<u>(1,252,796)</u>
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	<u>\$ 1,328,889</u>	<u>\$ 225,420</u>	<u>\$ 1,554,309</u>

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2009 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, 2009 were \$3.87 per MMBtu and \$61.08 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, H. Craig Clark, and our Chief Financial Officer, Michael N. Kennedy, 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 the Exchange Act, Rules 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. 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, 2011. The effectiveness of our internal control over financial reporting as of December 31, 2011 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, 2011 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 and subsidiaries' internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Forest Oil Corporation and subsidiaries' 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 and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 and subsidiaries and subsidiaries as of December 31, 2011 and 2010 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 21, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 21, 2012

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The names of the executive officers of Forest and their titles, ages, and biographies required by this Item are incorporated by reference to the information set forth under the caption "Executive Officers of Forest" included in Part I, Item 4A of this Annual Report on Form 10-K.

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, 2011 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 captions "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 auditor 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.

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, 2011 and 2010
3. Consolidated Statements of Operations—Years Ended December 31, 2011, 2010, and 2009
4. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2011, 2010, and 2009
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2011, 2010, and 2009
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2011, 2010, and 2009

(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 listed 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 dated October 14, 1993, incorporated herein by reference to Exhibit 3(i) to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 1993 (File No. 0-4597).
3.2	Certificate of Amendment of the Restated Certificate of Incorporation, dated as of July 20, 1995, incorporated herein by reference to Exhibit 3(i)(a) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.3	Certificate of Amendment of the Certificate of Incorporation, dated as of July 26, 1995, incorporated herein by reference to Exhibit 3(i)(b) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.4	Certificate of Amendment of the Certificate of Incorporation dated as of January 5, 1996, incorporated herein by reference to Exhibit 3(i)(c) to Forest Oil Corporation Registration Statement on Form S-2 (File No. 33-64949).
3.5	Certificate of Amendment of the Certificate of Incorporation dated as of December 7, 2000, incorporated herein by reference to Exhibit 3(i)(d) to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
3.6 †	Bylaws of Forest Oil Corporation Restated as of February 14, 2001, as amended by Amendments No. 1, No. 2, No. 3, No. 4, and No. 5.
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	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).

Exhibit Number	Description
4.10	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).
10.1 *	Forest Oil Corporation 1996 Stock Incentive Plan and Option Agreement, incorporated herein by reference to Exhibit 4.1 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 7, 1996 (File No. 0-4597).
10.2 *	First Amendment to Forest Oil Corporation 1996 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, 2001 (File No. 001-13515).
10.3 *	Second Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.4 *	Amendment No. 3 to Forest Oil Corporation 1996 Stock Incentive Plan dated December 6, 2005, incorporated herein by reference to Exhibit 10.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.5 *	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).
10.6 *	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).
10.7 *	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).
10.8 *	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).
10.9 *	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).
10.10 *	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).
10.11 *	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).
10.12 *	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).
10.13 *	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).
10.14 *	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).
10.15 *	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).
10.16 *	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).
10.17 *	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).
10.18 *	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).

Exhibit Number	Description
10.19 *	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).
10.20 *	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).
10.21 *	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).
10.22 *	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).
10.23 *	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).
10.24 *	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).
10.25 *	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).
10.26 *	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).
10.27 *	Form of Cash-Based Award Agreement, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 13, 2011 (File No. 001-13515).
10.28 *	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).
10.29 *	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).
10.30 *	Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.31 *	Form of Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.32 *	Form of Severance Agreement for Grandfathered Vice President, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.33 *	Form of Amendment to Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.34 *	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).
10.35 *	Severance Agreement, dated as of December 1, 2009, by and between Victor A. Wind and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation dated May 11, 2010 (File No. 001-13515).
10.36 *	Form of 2010 Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.37 *	Form of 2010 Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.38 *	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).

Exhibit Number	Description
10.39 *	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).
10.40 *	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).
10.41 *	Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.42 *	First Amendment to the Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, effective as of December 31, 2005, incorporated herein by reference to Exhibit 10.22 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.43 *	Amendment to Forest Oil Corporation Salary Deferral Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.44 *	Forest Oil Corporation 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.24 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2004 (File No. 001-13515).
10.45 *	Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.46 *	Amendment to Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.47 *	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated Effective as of January 1, 2005, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.48 *	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).
10.49 *	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).
10.50 *	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 10K for Forest Oil Corporation for the fiscal year ended December 31, 2011 (File No. 001-13515).
10.51 *	Forest Oil Corporation 2009 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.52 *	Forest Oil Corporation 2010 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2010 (File No. 001-13515).
10.53 *	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).
10.54 *	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).
10.55	Agreement for Purchase and Sale of Assets, dated as of August 5, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation, Linn Operating, Inc. and Linn Energy Holdings, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated August 5, 2009 (File No. 001-13515).
10.56	Agreement for Purchase and Sale of Assets, dated as of November 25, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation and SandRidge Exploration and Production, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 25, 2009 (File No. 001-13515).
10.57	Separation and Distribution Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian the Company 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).

Exhibit Number	Description
10.58	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).
10.59	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).
10.60	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).
10.61	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).
21.1 †	List of Subsidiaries of Registrant.
23.1 †	Consent of Ernst & Young LLP.
23.2 †	Consent of DeGolyer and MacNaughton.
24.1 †	Powers 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 (U.S. Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.2 †	Reserves Audit Report (Italian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
101.INS ±	XBRL Instance Document.
101.SCH ±	XBRL Taxonomy Extension Schema Document.
101.CAL ±	XBRL Taxonomy Calculation Linkbase Document.
101.LAB ±	XBRL Label Linkbase Document.
101.PRE ±	XBRL Presentation Linkbase Document.
101.DEF ±	XBRL Treasury Extension Definition

*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.

Index to Exhibits

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Forest Oil Corporation dated October 14, 1993, incorporated herein by reference to Exhibit 3(i) to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 1993 (File No. 0-4597).
3.2	Certificate of Amendment of the Restated Certificate of Incorporation, dated as of July 20, 1995, incorporated herein by reference to Exhibit 3(i)(a) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.3	Certificate of Amendment of the Certificate of Incorporation, dated as of July 26, 1995, incorporated herein by reference to Exhibit 3(i)(b) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.4	Certificate of Amendment of the Certificate of Incorporation dated as of January 5, 1996, incorporated herein by reference to Exhibit 3(i)(c) to Forest Oil Corporation Registration Statement on Form S-2 (File No. 33-64949).
3.5	Certificate of Amendment of the Certificate of Incorporation dated as of December 7, 2000, incorporated herein by reference to Exhibit 3(i)(d) to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
3.6 †	Bylaws of Forest Oil Corporation Restated as of February 14, 2001, as amended by Amendments No. 1, No. 2, No. 3, No. 4, and No. 5.
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	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).

Exhibit Number	Description
4.10	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).
10.1 *	Forest Oil Corporation 1996 Stock Incentive Plan and Option Agreement, incorporated herein by reference to Exhibit 4.1 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 7, 1996 (File No. 0-4597).
10.2 *	First Amendment to Forest Oil Corporation 1996 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, 2001 (File No. 001-13515).
10.3 *	Second Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.4 *	Amendment No. 3 to Forest Oil Corporation 1996 Stock Incentive Plan dated December 6, 2005, incorporated herein by reference to Exhibit 10.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.5 *	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).
10.6 *	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).
10.7 *	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).
10.8 *	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).
10.9 *	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).
10.10 *	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).
10.11 *	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).
10.12 *	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).
10.13 *	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).
10.14 *	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).
10.15 *	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).
10.16 *	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).
10.17 *	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).
10.18 *	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).

Exhibit Number	Description
10.19 *	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).
10.20 *	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).
10.21 *	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).
10.22 *	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).
10.23 *	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).
10.24 *	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).
10.25 *	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).
10.26 *	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).
10.27 *	Form of Cash-Based Award Agreement, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed June 13, 2011 (File No. 001-13515).
10.28 *	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).
10.29 *	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).
10.30 *	Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.31 *	Form of Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.32 *	Form of Severance Agreement for Grandfathered Vice President, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.33 *	Form of Amendment to Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.34 *	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).
10.35 *	Severance Agreement, dated as of December 1, 2009, by and between Victor A. Wind and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation dated May 11, 2010 (File No. 001-13515).
10.36 *	Form of 2010 Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.37 *	Form of 2010 Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.38 *	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).

Exhibit Number	Description
10.39 *	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).
10.40 *	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).
10.41 *	Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.42 *	First Amendment to the Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, effective as of December 31, 2005, incorporated herein by reference to Exhibit 10.22 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.43 *	Amendment to Forest Oil Corporation Salary Deferral Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.44 *	Forest Oil Corporation 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.24 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2004 (File No. 001-13515).
10.45 *	Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.46 *	Amendment to Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.47 *	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated Effective as of January 1, 2005, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2007 (File No. 001-13515).
10.48 *	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).
10.49 *	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).
10.50 *	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 10K for Forest Oil Corporation for the fiscal year ended December 31, 2011 (File No. 001-13515).
10.51 *	Forest Oil Corporation 2009 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.52 *	Forest Oil Corporation 2010 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2010 (File No. 001-13515).
10.53 *	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).
10.54 *	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).
10.55	Agreement for Purchase and Sale of Assets, dated as of August 5, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation, Linn Operating, Inc. and Linn Energy Holdings, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated August 5, 2009 (File No. 001-13515).
10.56	Agreement for Purchase and Sale of Assets, dated as of November 25, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation and SandRidge Exploration and Production, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 25, 2009 (File No. 001-13515).
10.57	Separation and Distribution Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian the Company 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).

Exhibit Number	Description
10.58	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).
10.59	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).
10.60	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).
10.61	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).
21.1 †	List of Subsidiaries of Registrant.
23.1 †	Consent of Ernst & Young LLP.
23.2 †	Consent of DeGolyer and MacNaughton.
24.1 †	Powers 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 (U.S. Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.2 †	Reserves Audit Report (Italian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
101.INS ±	XBRL Instance Document.
101.SCH ±	XBRL Taxonomy Extension Schema Document.
101.CAL ±	XBRL Taxonomy Calculation Linkbase Document.
101.LAB ±	XBRL Label Linkbase Document.
101.PRE ±	XBRL Presentation Linkbase Document.
101.DEF ±	XBRL Treasury Extension Definition

*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.

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Additional Information

INDEPENDENT RESERVE ENGINEERS

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244
214.368.6391

INDEPENDENT AUDITORS

Ernst & Young LLP
370 Seventeenth Street, Suite 3300
Denver, Colorado 80202
720.931.4000

STOCK

Common Stock Listed and Traded on:
The New York Stock Exchange
NYSE Symbol – FST

TRANSFER AGENT AND REGISTRAR FOR COMMON STOCK

Computershare Shareowner Services LLC
480 Washington Boulevard, 27th Floor
Jersey City, NJ 07310-1900
888.213.0882

TDD for Hearing Impaired: 800.231.5469
Foreign Shareholders: 201.680.6578
TDD Foreign Shareholders: 201.680.6610
www.bnymellon.com/shareowner/equityaccess

INVESTOR RELATIONS

Additional information, including an Investor Package, may be obtained from:
Forest Oil Corporation
Patrick J. Redmond, Vice President – Corporate Planning and Investor Relations
707 Seventeenth Street, Suite 3600
Denver, Colorado 80202
InvestorRelations@forestoil.com or visit our website at www.forestoil.com

ANNUAL MEETING OF SHAREHOLDERS

The annual meeting of shareholders of Forest Oil Corporation will be held at:
Marriott Hotel
1701 California Street
Denver, Colorado 80202
Tuesday, May 8, 2012 at 9:00 a.m. (MDT)

NON-GAAP FINANCIAL MEASURES

ADJUSTED EBITDA

In addition to reporting net earnings from continuing operations as defined under Generally Accepted Accounting Principles (GAAP), Forest also presents adjusted EBITDA from continuing operations, which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings from continuing operations before interest, income taxes, depreciation, depletion, and amortization (adjusted EBITDA). Adjusted EBITDA does not represent, and should not be considered an alternative to, GAAP measurements such as net earnings from continuing operations (its most comparable GAAP financial measure), and Forest's calculations thereof may not be comparable to similarly titled measures reported by other companies. By eliminating the items described above, Forest believes the measure is useful in evaluating its fundamental core operating performance. Forest also believes that adjusted EBITDA is useful to investors because similar measures are frequently used by securities analysts, investors, and other interested parties in their evaluation of companies in the oil and gas industry. Forest's management uses adjusted EBITDA to manage its business, including in preparing its annual operating budget and financial projections. Forest's management does not view adjusted EBITDA in isolation and also uses other measurements, such as net earnings from continuing operations and revenues to measure operating performance.

ADJUSTED DISCRETIONARY CASH FLOW

In addition to reporting net cash provided by operating activities of continuing operations as defined under GAAP, Forest also presents adjusted discretionary cash flow of continuing operations (adjusted discretionary cash flow), which is a non-GAAP liquidity measure. Adjusted discretionary cash flow consists of net cash provided by operating activities of continuing operations before changes in operating assets and liabilities, among other items. This measure does not represent, and should not be considered an alternative to, GAAP measurements such as net cash provided by operating activities of continuing operations (its most comparable GAAP financial measure), and Forest's calculations thereof may not be comparable to similarly titled measures reported by other companies. Forest's management uses adjusted discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations before changes in operating assets and liabilities, which fluctuates due to the timing of collections of receivables and the settlements of liabilities, and other items. Forest's management uses adjusted discretionary cash flow to manage its business, including in preparing its annual operating budget and financial projections. This measure does not represent the residual cash flow available for discretionary expenditures. Forest's management does not view adjusted discretionary cash flow in isolation and also uses other measurements, such as net cash provided by operating activities of continuing operations to measure operating performance.

Please reference Forest's 2011 10-K and Forest's year-end earnings press release dated February 21, 2012 for our reconciliation of non-GAAP financial measures to the most comparable GAAP measures.

Drill Bit Reserve Replacement Ratio

The drill bit reserve replacement ratio excluding revisions of 247% was calculated by dividing extensions and discoveries of 301 Bcfe by net sales volumes of 122 Bcfe.

Drill Bit F&D Costs

The drill bit finding and development costs excluding revisions of \$2.27 per Mcfe was calculated by dividing the sum of exploration and development capital expenditures (excluding land and leasehold acquisitions, asset retirement obligations, capitalized interest, and capitalized equity compensation) of \$683 million by extensions and discoveries of 301 Bcfe.

All-Sources Reserve Replacement Ratio

The all-sources reserve replacement ratio of 148% was calculated by dividing the difference of extensions and discoveries of 301 Bcfe and revisions of 120 Bcfe by net sales volumes of 122 Bcfe.

All-Sources F&D Costs

The all-sources finding and development costs of \$3.77 per Mcfe was calculated by dividing the sum of exploration and development capital expenditures (excluding land and leasehold acquisitions, asset retirement obligations, capitalized interest, and capitalized equity compensation) of \$683 million by the difference of extensions and discoveries of 301 Bcfe and revisions of 120 Bcfe.

FORWARD-LOOKING STATEMENTS

This report included forward-looking statements, including those related to oil and gas reserve estimates, within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see Item 1, header "Forward-Looking Statements" and Item 1A, header "Risk Factors," in Forest's 2011 10-K for additional disclosures.



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